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Summary

Offshore drill-rigs are yearly drilling a high number of oil and gas exploration and production wells worldwide. The rate does not seem to decline and is moving into deeper waters and more hostile environments. Hostile environments demand an increase in the complexity of the well, and more advanced drilling methods are required.

Dual Gradient Drilling (DGD), an unconventional drilling technique, is a method used to address these new challenges. DGD is a technique that uses fluids of varying density to provide a more stable bottom-hole pressure (BHP) which gives a desired annular pressure profile to increase well performance, improve personnel safety and reduce the Non Productive time (NPT). With a DGD system, it is possible to drill a well with a narrow and complex pressure window, whereas conventional drilling techniques would reach its limitations and fail.

Five major DGD methods, both pre-BOP and post-BOP methods, including dynamics and the tools needed and for optimal system operation, have been reviewed in this thesis:

- Riserless Mud Return (RMR), which is a pre-BOP DGD system
- Subsea Mudlift Drilling (SMD)
- Controlled Mud Pressure (CMP)
- EC-drill
- Low Riser Return System (LRRS)

post-BOP system

The various methods have similar, but also their own way of trying to compensate for the pressure variations exerted on the wellbore during connection operations.

The U-tubing effect is one of several challenges with DGD and is highlighted in this thesis.

MATLAB was used for mathematical simulations to study parameters affecting the DGD during connection operations. Henceforth suggesting a lighter liquid and a flow rate, and using Kaasa’s Model to automate the control system.

Acknowledgements

The given report is a further understanding of the dual gradient drilling technology (DGD) with suggestions in the sensitivity of parameters affecting DGD. A master thesis given by supervisor Dan Sui, carried out during the fall semester at the University of Stavanger 2014.

I would like to thank my supervisor Dan Sui for the opportunity to write this thesis, for and her guidance and availability throughout the semester. Also a special thank you to my dad for his understanding and support.

Table of content

Innholdsfortegnelse

Nomenclature

Abbreviations

BHA	Bottom Hole Assembly
BHP	Bottom Hole Pressure
BOP	Blowout Preventer
BP	Booster pump
BPP	Back Pressure Pump
CBHP	Constant Bottom Hole Pressure
CMP	Controlled Mud Pressure
DGD	Dual gradient drilling
DSV	Drill String Valve
ECD	Equivalent Circulating Density
GoM	the Gulf of Mexico
HSE	Health, Safety and Environment
LRRS	Low Riser Return System
MLP	Mudlift Pump
MPD	Managed Pressure Drilling
MRL	Mud Return Line
NPT	Non-Productive Time
PMCD	Pressurized Mud Cap Drilling
RCD	Rotating Control Device
RIJ	Riser Interface Joint
RL	Return Line
RMR	Riserless Mud Return
ROP	Rate of Penetration
SMD	Subsea Mudlift Drilling
SMO	Suction Mudule
SPM	Subsea Pump Mudule
SPU	Solids Processing Unit
SRD	Subsea Rotating Device
TD	Target Depth

Chapter 1

1 Introduction

This thesis deals with dual gradient drilling technology that makes it possible to reach target location when drilling in deep-water environments. It gives literature overview, enlightening the history and the current status of the use of dual gradient drilling, and showcases sensitivity analysis of drilling parameters like flow rate of main pump, mud density, riser fluid level and effect of back pressure pump. An optimal choice of lighter fluid density and an optimal choice of flow rate of main pump were advocated to enhance the capacity of DGD in the simulations. The automated DGD method is presented to show good performance DGD operations where a stable BHP is maintained during connection operations by automatically adjusting the mud level in the riser.

The thesis is structured with a literature study on the DGD system, the different methods of DGD, modified equipment and the key factors for DGD from chapter 2 to chapter 5.

Chapter 6 discuss the optimization of suggestion of parameters.

Chapter 7 provides information on control theory and Kaasa's model for DGD systems.

Chapter 8 is where the simulations are presented.

Chapter 2

2 Dual Gradient Drilling

This chapter defines DGD as a method for Managed Pressure Drilling (MPD) techniques. It will give better understanding of the DGD concept and give reasons for the implemented benefits.

2.1 Managed Pressure Drilling

The International Association of Drilling Contractors (IACD) is defining Managed Pressure Drilling (MPD) as "*an adaptive drilling process used to more precisely control the annular pressure profile through-out the well bore. The objectives are to ascertain the down-hole pressure environment limits and to manage the annular hydraulic pressure profile accordingly*."[1]

MPD is an unconventional drilling technique that allows:

- The use of a lower density drilling fluid in the riser that floats on top of the heavier density fluid, minimizing the overbalance pressure in the well (DGD).
- Drilling with total lost returns where everything is forced into the formation zones with a drilling hazard (PMCD).
- Adjusting the effect of circulation friction loss or equivalent circulating density (ECD) to stay within the pore pressure and fracture pressure gradients (CBHP).
- Drilling with an automated choke in the annulus return system (HSE)

Using these techniques will make the BHP easily controlled and changed according to safety and beneficial limitations.[7]

MPD is preferred when drilling more challenging wells, which is either impossible or not economically beneficial to drill with conventional techniques. MPD is starting to be broadly acknowledged in the drilling industry, and the main advantages are:[1][7][8]

- Reduced Non-Productive Time (NPT) and drilling days
- Increased well performance and wellbore integrity
- Improved well and personnel safety

2.2 DGD Background

An overview of DGD, given the understanding of MPD techniques in the previous section.

2.2.1. DGD Definition

The DGD technology has in resent stages shown that it is possible to drill in deep-water environments and depleted reservoirs [2], which no engineer in the industry thought possible just over a decade ago. This new way of thinking differentiate from conventional drilling by drilling the wellbore with two different annulus fluid gradients in place.[9]

The International Association of Drilling Contractors (IACD) currently [5] defines dual gradient drilling as the "*creation of multiple pressure gradients within select sections of the annulus to manage the annular pressure profile. Methods include use of pumps, fluids of varying densities, or combination of these.*" [6]

The usage of fluids with different densities in DGD creates a pressure gradient, which better suits the pore pressure and formation pressure gradients in the well bore. The lighter density fluid, primarily located in the riser, floats on top of the more dense drilling fluid in the reminder of the well length, and the well pressure is henceforth the sum of these two different fluids. The dual gradient system may significantly change the bottom-hole ECD without having to change the density of the mud or the pump rates. Being able to adjust the lighter density fluid in the riser to control the BHP, can ensure that the wellbore pressure is kept within the pore pressure and fracture pressure gradient accommodating a longer depth interval widening the drilling window, and providing a more efficient and safe well. The denser circulating fluid bypass the lighter fluid from seabed to surface by one or more small-diameter return lines. By utilizing the return line, DGD eliminates the "pump and dump" practice, where all returns are dumped and left on the seafloor. This allows a “fluid of choice”, rather than a cheap and disposable drilling fluid.[1][2]

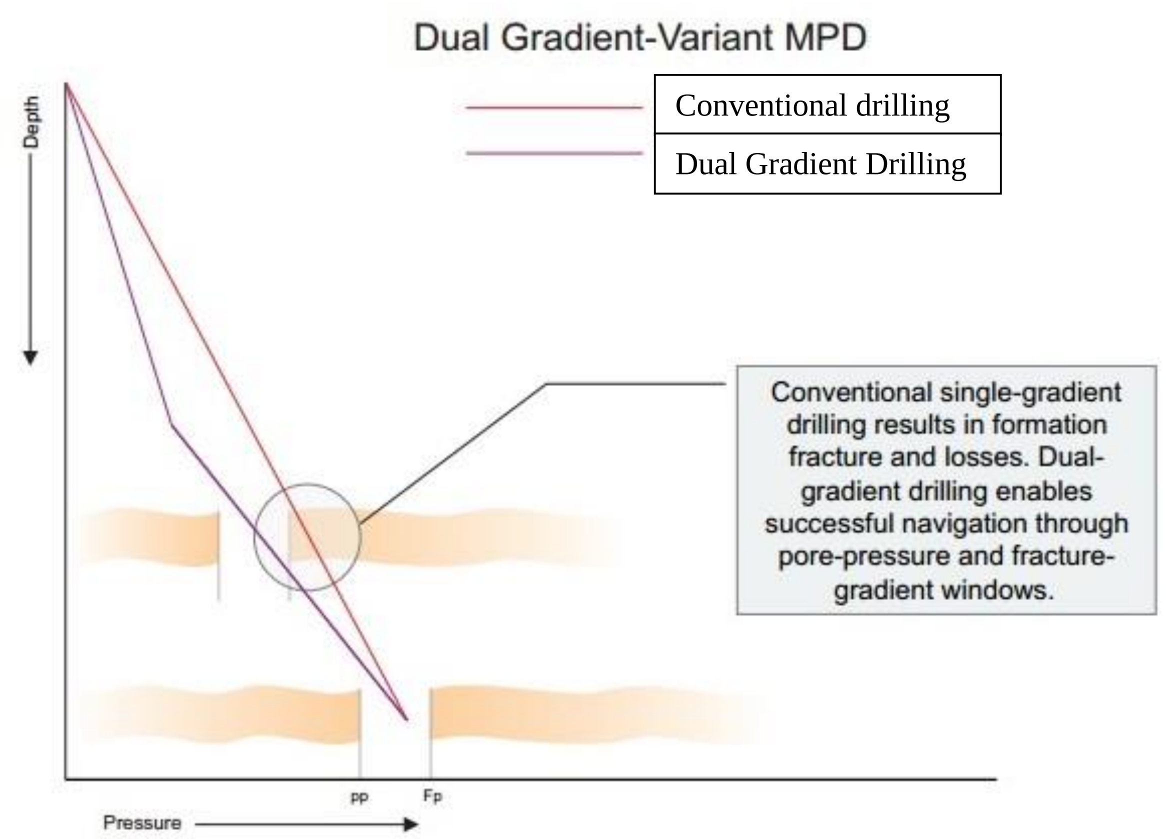

Figure 2.1: Pore pressure and fracture pressure gradient in Conventional drilling vs DGD[9]

2.2.2 History

Hydrocarbons being the world leading energy resource and still increasing in demand, the industry within oil and gas had to search for resources in deep water environments. In the early 1960s the industry wanted to address the deep-water challenges by eliminating the need for a riser to drill a well. The concept was referred to as “Riserless Drilling”. However, the technology for developing the concept was insufficient at the time. In addition, the operating water depths were shallow enough to use conventional riser-based drilling technology, providing no demand for the new concept. Consequently putting everything on hold.[2]

In 1990s, several significant reservoir discoveries were made in deep-water environments in the Gulf of Mexico (GoM). The limited availability of deep-water drilling rigs motivated operators and contractors to develop a system that could drill in deep-water environments from a shallow water conventional drilling rig. Thus creating new attention on DGD hoping it could be the solution they were looking for. The advantages for a DGD system were well documented, however, the challenges in developing the system required a "new way of thinking".[1][2][10][12]

In 1996, the Subsea MudLift Drilling Joint Industry Project (SMD-JIP) was formed to study this alternative deep-water drilling technique, which later became formally known as DGD. The success of the technology was relying on the development of a mud lift pump sufficiently robust to move embedded solids and mud fluids to the surface without clogging intermediate drilling system components.[12]

In September 2001, after a few years of developing the system, the semisubmersible drill-rig *Ocean New Era* successfully drilled the first full scale field DGD test well at 300m water depth in GoM. The success of the test showed the world a working system, which ensured commercial deployment and acceptance in the marketplace.[11][12][13]

2.3 Dual Gradient Drilling - Components

This section provides overview of DGD components before discussing different DGD methods in the next section. Further description of the most essential equipment and modified components is given in chapter 4.

Most of the equipment and tools used in DGD is similar or very much the same for several of the DGD methods. Figure 2.2 shows a brief and simplified overview of the components used in a DGD operation. DGD operations require moderated components and equipment of new design, compared to what found in conventional drilling technology.

Most of the equipment or modified components used in a DGD operation:[1]

- Rotating Control Device (RCD)

- Subsea Control Module
- Mud Return Line
- Suction Control Module (SMO)
- Riser Interface Joint, allows SPM to tie onto the riser
- Mudlift Pump
- Subsea Rotating Device
- Solids Processing Unit
- Back Pressure Pump, to control and create back pressure
- Drill String Valve (DSV)
- Winch and Umbilical
- Hose Handling Platform
- Power Supply and Control Container
- Other chokes, valves and more

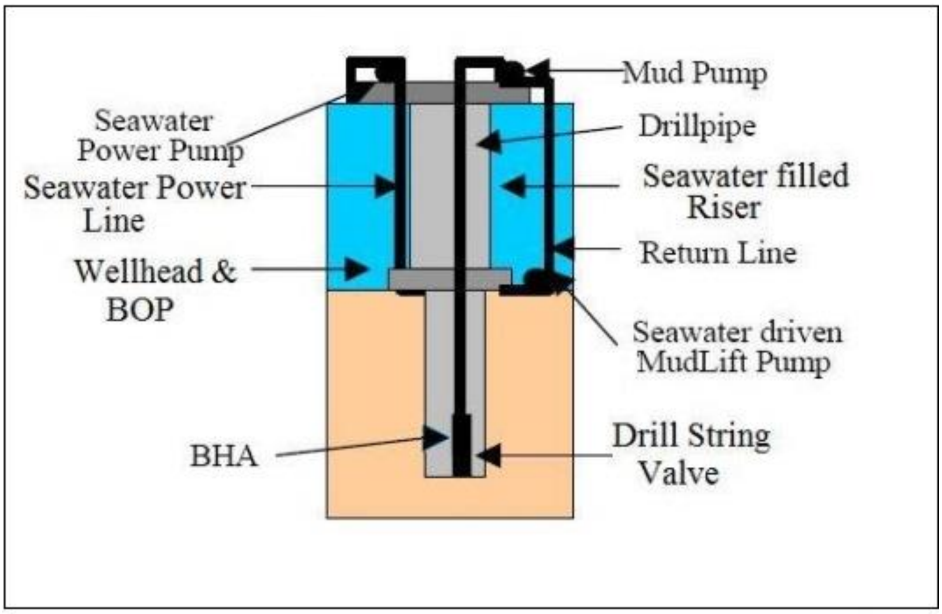

Figure 2.2. Simple overview of DGD components[10]

DGD operations use a relatively small diameter Return Line (RL) to circulate the heavier drilling fluids from the wellbore to the respective mud system on the surface. During connection and circulation, a seawater filled riser is used to avoid mixing the more dense drilling fluid in the wellbore with the less dense fluid in the riser.

The acquired dual gradient effect is then held by using a subsea mudlift pump, which is connected to the annulus of the wellbore below the riser and the BOP. The mudlift system transfer the more dense fluid, including cuttings from the wellbore to the surface through the RL.[10]

The operational options for the subsea mudlift pumps is either to keep the inlet pressure constant, keeping the circulation at a constant rate or being used in a manual override mode. The main reason for a DGD setup is to keep a constant BHP, which gives reason to operate the mudlift pump with a constant inlet pressure equal to the hydrostatic pressure of the less dense drilling fluid in the riser.[10]

Chapter 3

3 Methods of Dual Gradient Drilling

The International Association of Drilling Contractors' Dual Gradient Drilling Subcommittee classifies the dual gradient systems into two main categories:

- Pre-BOP
- Post-BOP

A Pre-BOP dual gradient system being installed before running the blowout preventer (BOP) and a Post-BOP gradient system which is installed after running the BOP. Each with their own sub-categories for additional separation of the different methods of DGD within the main classifications. Sections highlighted in purple in the following classification trees are focused. Section highlighted in orange (subchapter 3.2) will not be discussed. Dilution, highlighted in grey and being a part of the active DGD system, is included in the classification tree, but not focused.

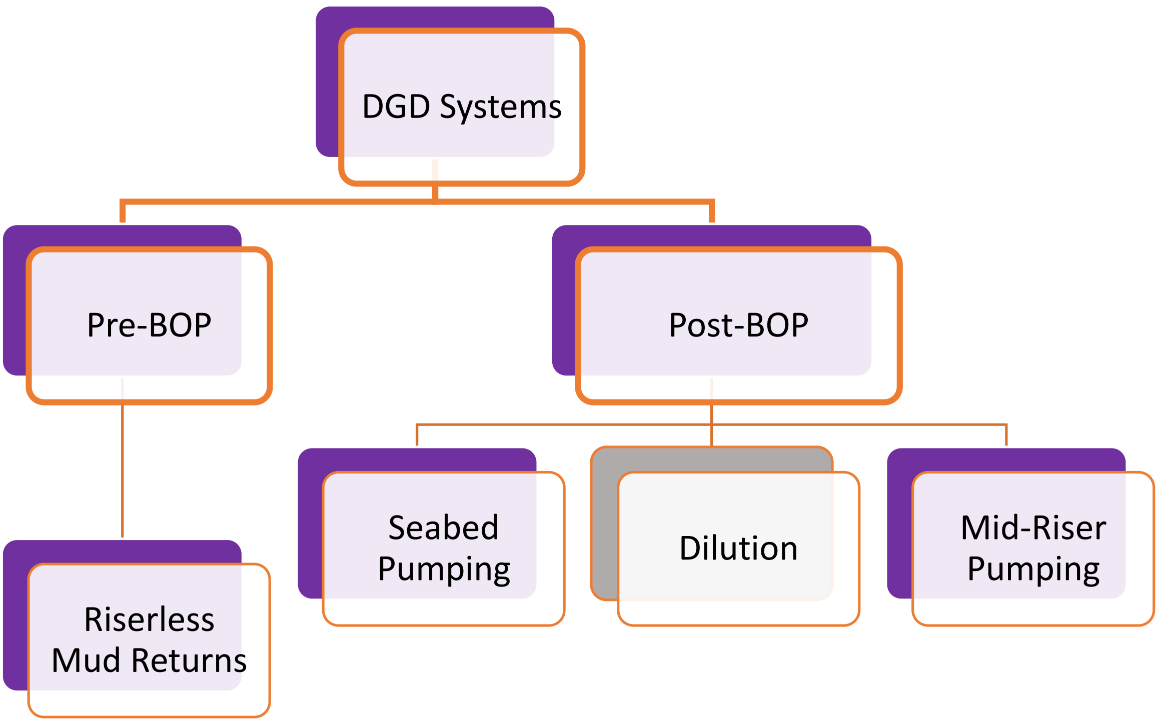

Figure 2.3. Dual Gradient Drilling Classification tree

3.1 Pre-BOP

The Pre-BOP classification contains only one developed method for DGD.

3.1.1 Riserless Mud Recovery

The Riserless Mud Recovery (RMR) is developed by the research facility AGR, and is the only commercial pre-BOP DGD system on the market today.

When drilling with conventional drilling techniques in deep-water environments the top hole sections cuttings and mud returns are dumped and left on the seabed.. Henceforth, no need for a riser from seabed to the surface. Normally a light drilling fluid (seawater or properties close to seawater) is used. However, if a more heavy drill fluid is needed to drill the top section, a relatively cheap water based bentonite mud is normally used. To limit the safety, environmental and economically disadvantages, which this “pump and dump” practice indicates, a RMR system is used.[2][15]

RMR is an innovative method for returning mud and cuttings from the top hole drill section to the rig before the marine riser is run and the lower sections of the wellbore is drilled. It provides a closed circulating system by the use of a mud recovery line and a subsea pumping system connected to the subsea wellhead. This allows treatment and cleaning of used mud, and enables an option of re-using the mud instead of leaving it on the seabed. The use of a more expensive engineered drilling fluid is economically justified improving the quality of the top hole. A more stable top hole section is then achieved by making it easier to lower the casing string to the bottom, and thereby ensuring a better chance of a good quality cement job, and furthermore increase the stabilisation of the wellhead. A longer surface casing can be set eliminating the 20” surface casing and successfully setting the 13 $^{5}/_{8}$” casing down to more than 2350m, which significantly reduces the weight and work involved.[1][15]

Benefits overview:

- Primary well control before the BOP and riser is installed
- Improved hole stability

- Deeper surface casing
- Fewer casing strings
- Zero discharge at seabed
- Improved wellhead stability

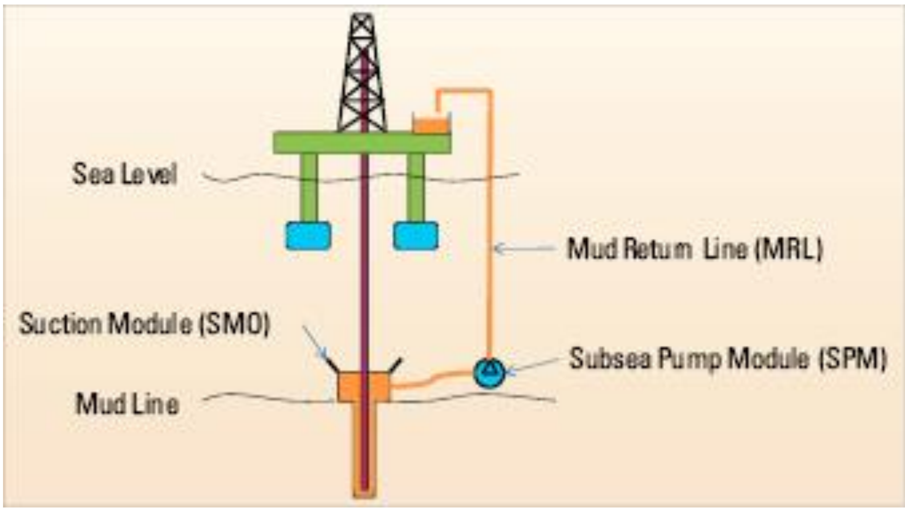

Figure 3.1 Riserless mud recovery uses a subsea pump module located near the seabed to pump fluid and cutting returns from the well to the rig mud-treatment system via the Return Line.[16]

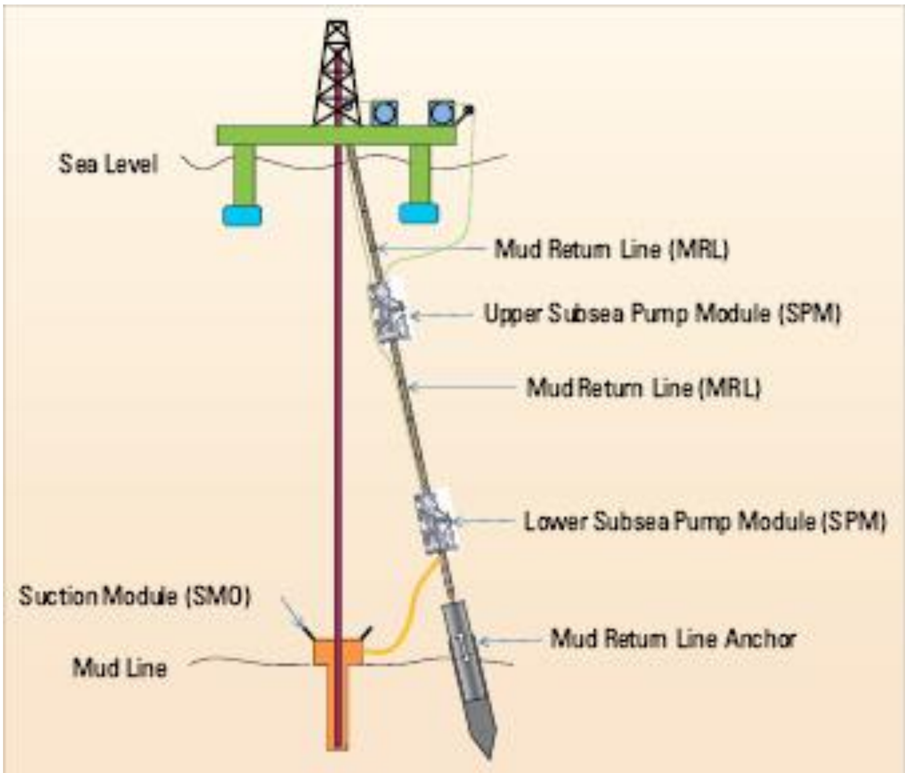

Figure 3.2 Deepwater RMR uses an anchoring system to keep the Return Line from swinging into the drill string.[16]

3.2 Post-BOP

A layout of four active post-BOP DGD methods is being presented in the subchapters below.

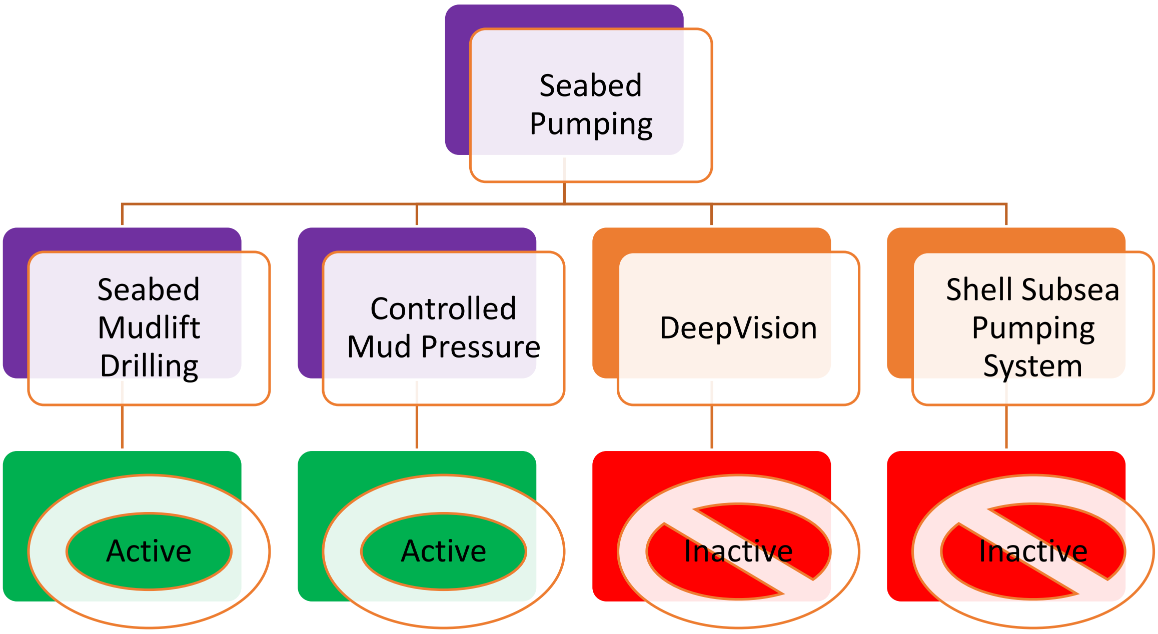

Figure 3.3 DGD methods under the Seabed Pumping classification.

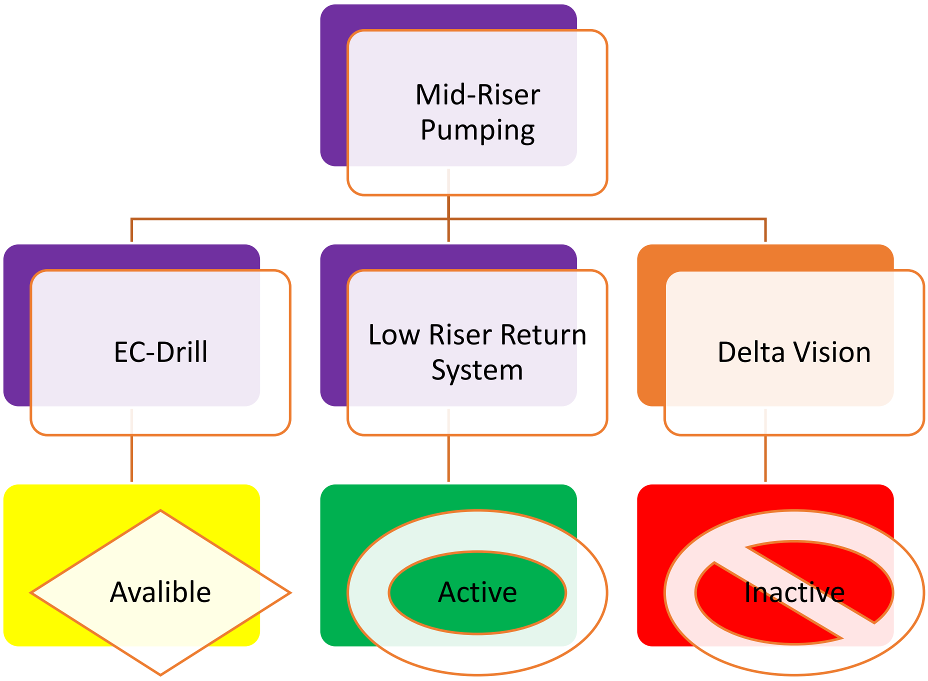

Figure 3.4 DGD methods under the Mid-Riser Pumping classification.

3.2.1 Subsea Mudlift Drilling

The Subsea Mudlift Drilling (SMD) technology was developed and proven by the Subsea Mudlift Drilling Joint Industry Project for deep-water operations between 1200-3050m. The SMD system consists of a seawater driven positive displacement pump (Mudlift Pump), a seawater filled riser, Mud Return Line (MRL), Subsea Rotating Diverter and a Solid Processing Unit (Chapter 4).[4][12]

The Mudlift Pump (MLP) is the key component to a SMD system. It is connected on the well above the BOP. It withdraws the mud from the well and pumps it back up to the surface through the RL, which again is connected to the drilling riser. A rotating diverter separates the seawater in the riser and the more dense drilling fluid in the wellbore before being pumped to the surface. Having the marine riser filled with seawater, or a fluid close to seawater density, reduces the quantity of needed mud for the drilling operation and maintain a mud fluid interface at any depth in the riser. This reduces the rig load and mud maintenance costs.[2]

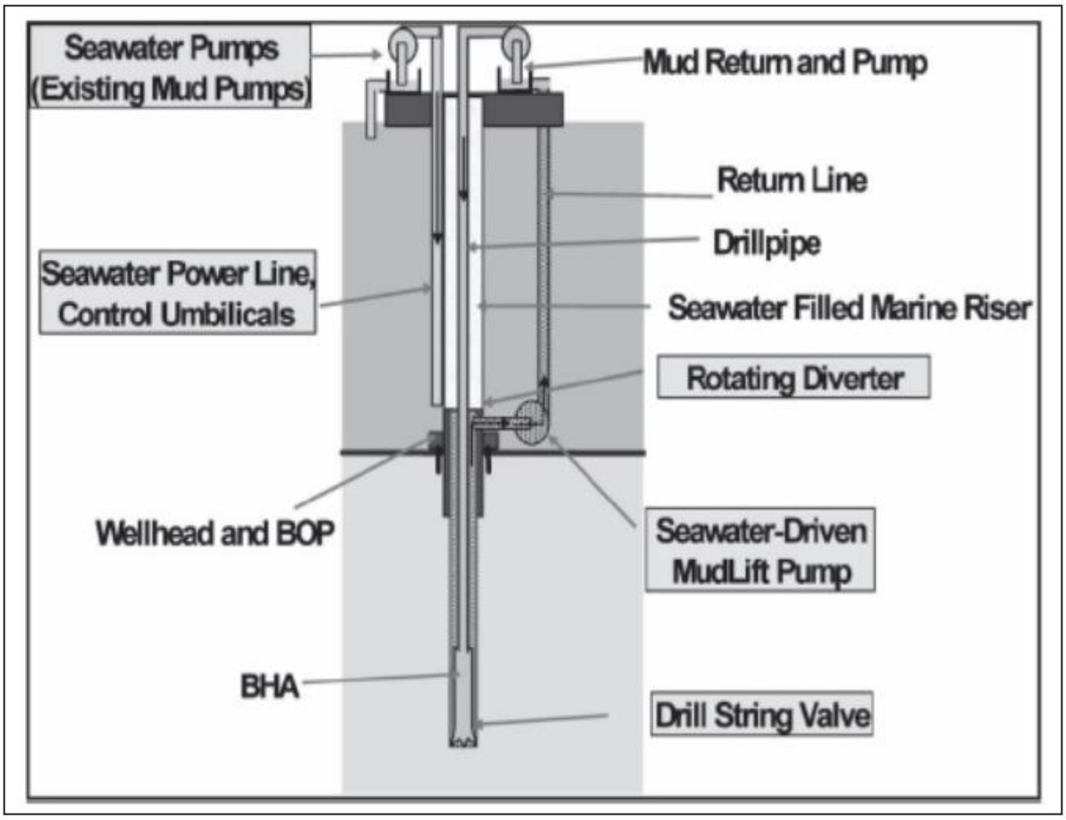

Figure 3.5 Subsea Mudlift Drilling arrangement[10]

3.2.2 Controlled Mud Pressure

Controlled Mud Pressure (CMP) enables better control of the BHP and the Equivalent Circulating Density (ECD). A subsea pump is used to return drilling fluid from an outlet close to the seafloor and up to the rig. The marine riser is filled with a seawater dense mud, and a small section of more dense mud close to the bottom. The more dense drilling fluid will rest at a level above the outlet connection point for the pump, and the rest of the riser will consist of the less dense fluid. This creates the dual gradient pressure profile, and the BHP is expressed as the sum of the two different fluids.[1]

Necessary adjustments or changes to the BHP and ECD is done by adjusting the level of the more dense drilling fluid with. This level adjustment is done by increasing or decreasing the return pump rate relative to the surface pump rates. In addition, CMP system can be used not only to change the ECD in drilling operations, but also during cementing, completion and intervention.[2]

The CMP system operates without a rotating seal, meaning an open–to-atmosphere system, providing free movement and adjustment of the interface of the two fluids in the riser. The CMP technology provides most potential in deep-water wells where the potential pressure from the fluid is a significant part of the BHP.[2]

3.2.3 EC-Drill

EC-Drill is, according to the research facility AGR, a "*Controlled Annular Mud Level technique for post-BOP hole section drilled from Floating Drilling Units while controlling BHP, Pressure Gradient and ECD*" and is made to operate within boundaries of conventional well control.[5]

EC-Drill technology is used for drilling the deeper sections of the well, and rather more an available DGD method from AGR than an active method. It uses the same concept as CMP by using a subsea pump to raise or lower the mud level in the riser to control the BHP. EC-Drill reaches its full potential in deep-water wells with a narrow pressure window. Too much pressure and the formation will fracture, too little will increase the chances of wellbore influx and hole instability. It offers more control while drilling and enable operators to reach deep targets not possible with traditional drilling techniques. EC-Drill is also applicable in reaching targets in depleted fields, low mud weight environments where mud loss to the formation or reservoir are the issue, and in high mud weight environments with a narrow margin.[1][17]

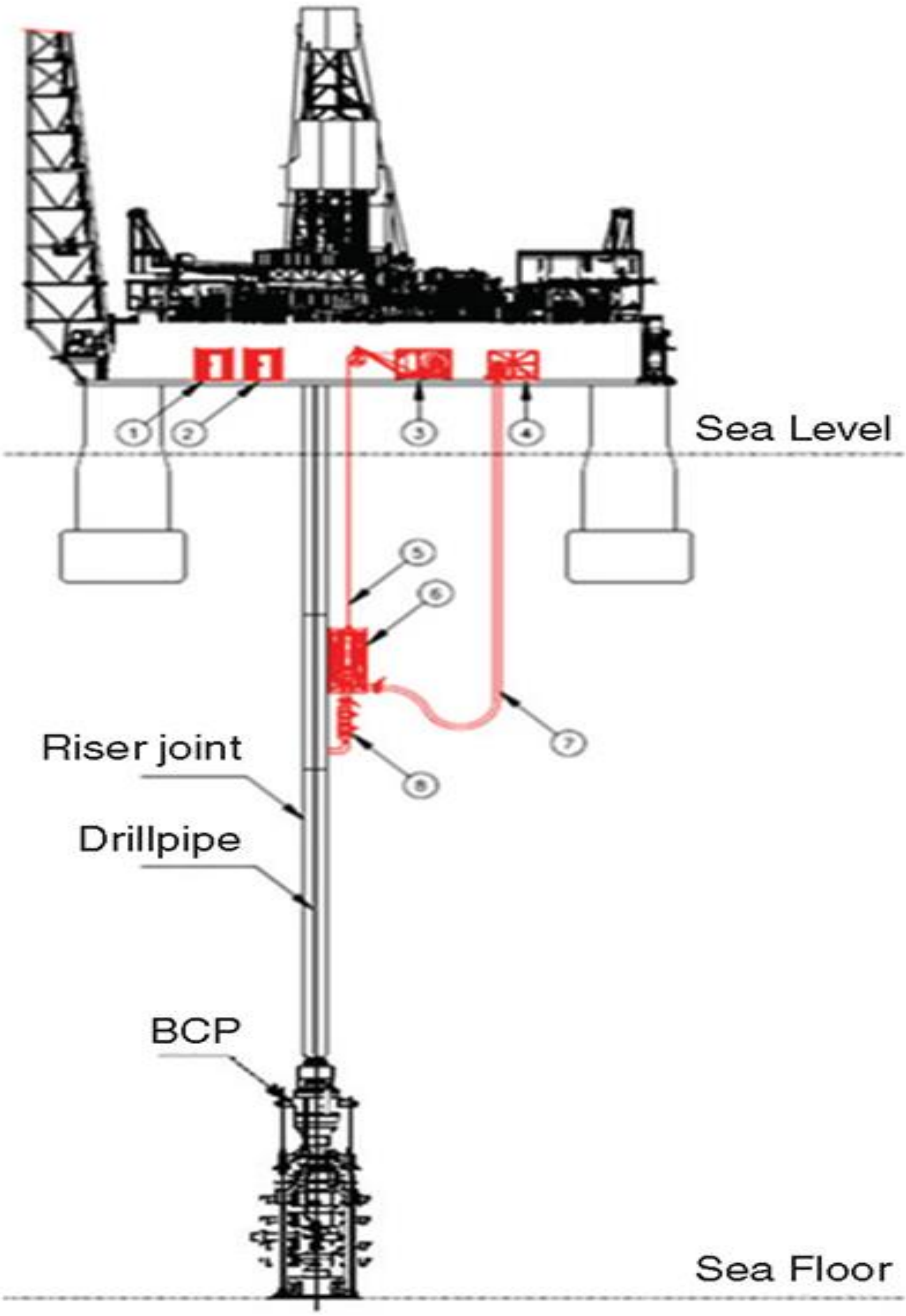

Figure 3.6 Typical EC-Dril setup [19]

Figure 3.6 showing a typical EC-Drill configuration. Optional configurations exist; however, the figure gives a good understanding of how the setup looks like.

1. Office/Tool Container
2. Control Container
3. Umbilical Winch
4. Hose Handling Platform
5. Umbilical
6. Subsea Pump Module (SPM)
7. Mud Return Line
8. Riser Tree

The Subsea Pump Module (SPM) is connected to the riser at a predetermined point according to the length of the well, the volume of drilling fluid in the wellbore, mud weight, flow rate, and the well configuration. The EC-Drill within the SPM pumps up drilling fluid to the rig during circulation by an increase in flow rate and lower the level of fluid in the riser to decrease and stabilize BHP.

The EC-Drill pump can adjust mud level in the riser anywhere between SPM connection and top of the riser. Increasing or decreasing flow rate of the EC-Drill pump will adjust the mud level accordingly, but also pumping additional mud into the riser by the use of rig pumps and riser boost lines will manipulate the pressure, while providing a constant flow rate on the EC-Drill pump.[1]

3.2.4 Low Riser Return System

Low Riser Return System (LRRS) is an open-to-atmosphere Managed Pressure Drilling system, which utilize a single gradient drilling system to reach desired BHP. Even though catalogued as a MPD system it performs like a DGD system. The riser is only partially filled with mud, where the rest is filled with nitrogen gas (N_2) at roughly atmospheric pressure. Air is excluded due to danger of explosion when Oxygen (O_2) connects with flammable hydrocarbons in gaseous state, like methane gas. Nitrogen is a clean, dry, and passive gas that prevents oxygen to feed a potential fire, therefore having no seal between the mud and the gas is essential. This is to mix flammable hydrocarbons accumulating in the riser with nitrogen rather than having it trapped beneath the seal in the riser. Even though referring to LRRS as an open system, a wiper element at the top of the riser beneath the Rotating Kelly Bushing (RKB) seals the riser.[10]

The LRRS utilizes a subsea pump and a booster pump at the surface in addition to the main mud pumps at the rig. Both operating within the boundaries of 36 – 360 m^3/hour. Mud and cuttings are returned to the surface via the submergible pump through the return line. The booster pump is used to fill the riser annulus when needed. An adjustable subsea choke is situated to control the backpressure in the system. [1][10][20]

LRRS components listed below[1]:

- Riser Interface Joint (RIJ), Connection point
- Mud Return Line
- Subsea Choke (SSC)
- Subsea Mud Pump
- Riser wiper / wiper element
- Power umbilical
- Pump and Control Systems
- N2 Purge System (NPS)

Ocean Riser Systems (merged with AGR Enhanced Drilling), which developed LRRS, designed two versions of the system to cope with the different well control procedures [1] [10]:

1. LRRS Light / $LRRS^{ECD}$
   - Used with conventional well procedures to compensate for the ECD effect during mud circulation in the well while drilling. This require minimal rig integration. Good for drilling the reservoir section.

2. LRRS Heavy / LRRS+
   - Used with higher mud weight than conventional mud. To eliminate the increased risk of formation fracture with the use of a heavier mud, the fluid riser level during

static and dynamic operations is lowered. This system is reliant on modified well control procedures which include a subsea drilling choke, additional equipment as well as modified well control training.

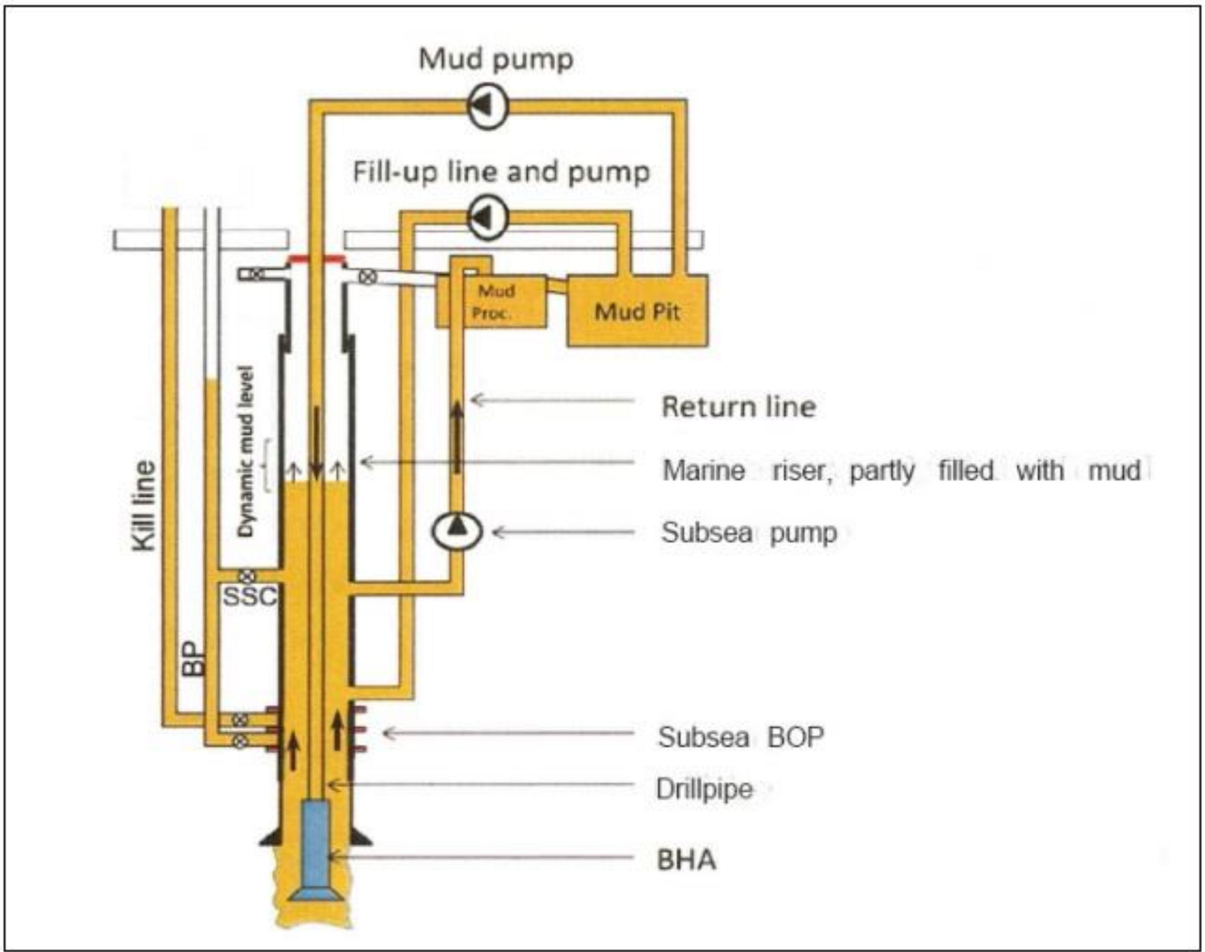

Figure 3.7 Overview of LRRS Configuration [20]

Chapter 4

4 DGD Equipment

Several DGD methods utilize the same or similar equipment. This chapter provides description of the equipment used in the different DGD operations discussed in the previous chapter.

4.1 Subsea Pump Module

The SPM is a module that provide a housing support frame for the installation of subsea motors, different pumps, hose interfaces, and control systems needed in the different DGD operations. It is in principal the same for all DGD systems; however, the module is modified to support the different DGD components to the chosen DGD method. It is one of the most essential components in drilling with dual gradient, and all DGD methods utilize a SPM to provide a dual gradient effect.

Figure 4.1 AkerSolutions SPM[22]

The return flow of the more dense drilling fluid with cuttings from the wellbore is pumped to the surface for processing by the SPM. It is therefore crucial to have the SPM connected to the riser below the minimum interface point of the two different dense mud fluids.

The SPM can be run on the drill pipe, the riser, or launched of the side of the rig by a winch.[1][2]

4.2 Mud Return Line

The Mud Return Line (MRL), mentioned as the return line (RL) in previous sections, is usually a soft rubber hose with 6” diameter. It is connected to the SPM. It transports mud and cuttings to the surface, which is being pumped by the SPM. The soft rubber is designed to withstand forces triggered by currents in the sea and movements of the drill rig.

The low diameter of the mud return line provides a faster flow speed of the mud transported to the surface. This is because the cross section area of the riser annulus is greater than the one of the mud return line. This will reduce the time which mud is exposed to the cold temperate seawater, therefore reducing the degrading of mud properties.[2]

Figure 4.2 Mud Return Line[23]

4.3 Suction Control Module

The Suction Module (SMO), usually used when drilling with the RMR system, collect cuttings and mud returns when exiting the wellhead. It is attached to the wellhead at the sea floor, and a flexible suction hose is run from the SMO to the SPM, which is connected by a remotely operated vehicle (ROV). The hydrostatic pressure exerted by the seawater and the circulating mud stabilize the fluids in the SMO.

It is used when drilling the top hole section before the riser is set, and is deployed on the drill-string before lowering the system. This means that the drill string must pass through the SMO before a drill bit can be connected. If change of drill bit in the top hole section is necessary, the whole system needs to be raised to the surface. However, different models are provided for different types of wellhead design.

The SMO is fitted with cameras and lights to monitor the mud level. In addition, a pressure transducer is fitted to register the hydrostatic pressure of the mud column. This makes it possible for computers to keep a constant mud level inside the SMO by pumping returns to the surface at the same rate as returns exit the well. The cameras can also be used to capture images of gas (shallow and/or drilled) escaping the well. This gas is seen as small bubbles rising out of the mud and into the seawater inside the SMO. This makes it possible to monitor the amount of escaped gas.[1}[2][24]

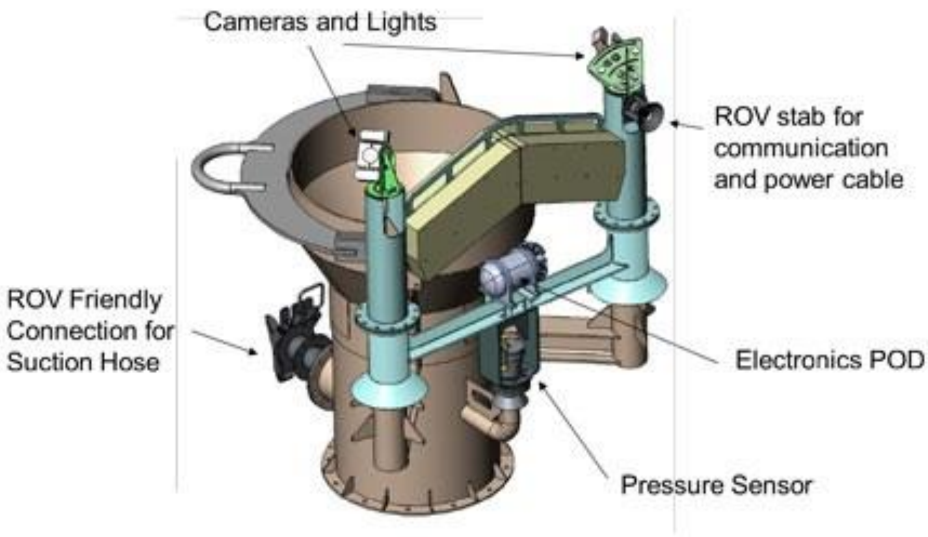

Figure 4.3 Suction Control Module[16]

4.4 Solids Processing Unit

The Solids Processing Unit (SPU) is crushing solids and mud returns too big to pass through the mudlift pumps. This is to avoid plugging of the pumps and the return line. It then feeds the

SPM with the processed mud through a filter, and the mud is then pumped back up to the surface. In DGD and by use of mudlift pumps and small diameter return lines, the debris from SPU should not exceed sizes over $1^{1}/_{2}$”. Several valves control the flow should the need for flushing the SPU arise.[2][13]

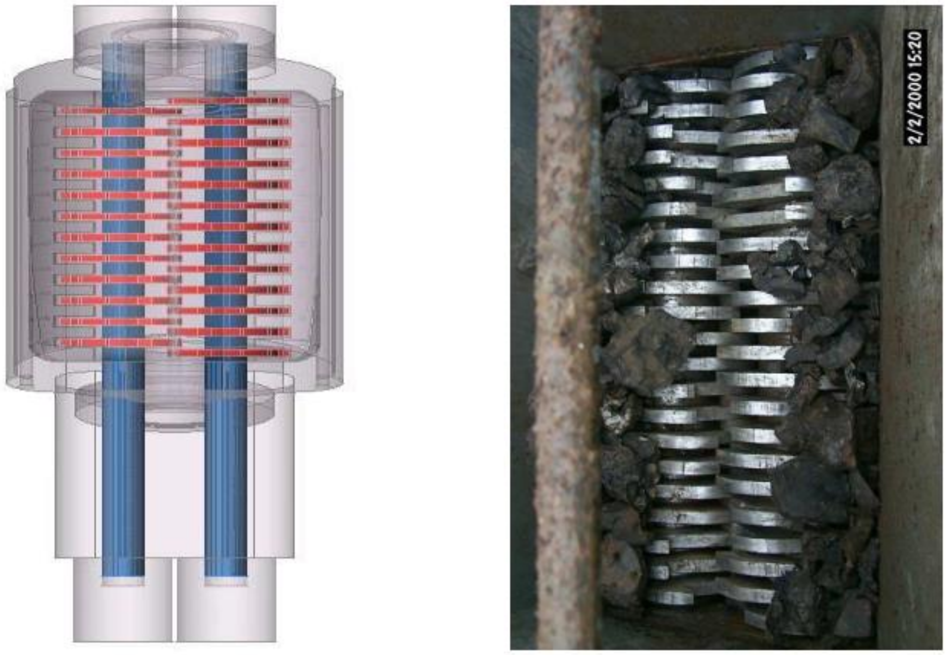

Figure 4.4 Solids Processing Unit[26]

4.5 Subsea Rotating Device

The Subsea Rotating Device (SRD) diverts drilling fluid to establish a dual gradient effect. It separates seawater in the riser from the more dense drilling fluid in the well, as well as diverting mud and cutting returns from the annulus to the SPU. It is deployed through the marine drilling riser and sits between the riser and the wellbore providing an interface between the seawater dense fluid and the heavier drilling fluid in the wellbore. It also ensures that gas does not enter the riser from the wellbore and keeps the well slightly pressurized (3-4 bar) in order to feed the SPM with the more dense drilling fluid in the wellbore. It operates as a rotating control device (RCD) used in conventional drilling, however modified to sit between two different densities of mud in the riser directly above the BOP and not as a pressure barrier between drilling fluid and the rig personnel.[1][2][25]

4.6 Drill String Valve

Unfortunately, the laws of nature frequently supersede the operational desires in the oil and gas industry. When slowing down the flow rate by shutting down the pumps prior to making a connection, a U-tube phenomenon (discussed in chapter 5) occurs in the DGD system. The purpose of the drill string valve (DSV) is to prevent this phenomenon to complicate the drilling operation by restricting flow in the drill-string. The DSV is located in the BHA near the bit to support the hydrostatic pressure column in the drill string during connection. The DSV is spring-loaded and pushes back against the charge in the mud when the rig pumps exert a positive pressure force. When flowrate decreases and the hydrostatic pressure in the annulus becomes higher than the one in the drill-string, the valve closes.[2][26]

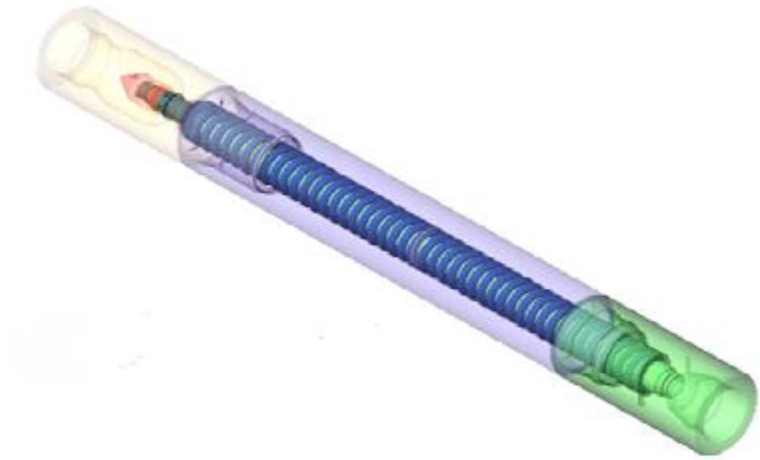

Figure 4.5 Drill String Valve[26]

4.7 Winch and Umbilical

An umbilical winch provides power and communication between the control container and the SPM. Control signals are transmitted through fibre optics in the umbilical to prevent electrical interference from the high voltage lines powering the SPM motors. The umbilical winch, also designed to launch and retrieve the SPM, is mounted on the drill rig[1]. A good illustration is given in Chapter 3, figure 3.6.

4.8 Other DGD Drill Rig Equipment[1][28]

Hose Handling Platform

- A hang off system for the MRL. Where MRL is connected to the rig and mud returns are sent to processing when pumped to the surface.

Control Container

- Monitoring SMO, speed drives and transformers. Connects all control systems.

Office/tool Container

- Controlling the DGD system. Communication office. Where all operations in the DGD system is monitored and controlled.

Generator

- Supplies with electrical power to run the DGD operations if needed or desired by operators.

Chapter 5

5 Advantages and Challenges of DGD

In deep-water drilling, the dual gradient drilling technology provides several advantages over conventional drilling technology and techniques. Due to either economically or operational aspects, some reservoirs are unreachable with conventional single gradient drilling. Applying a DGD system will significantly increase the possibility to reach these reservoirs. However, new technology brings new challenges. In this chapter the key drivers and the main challenges for the DGD system is presented.

5.1 Advantages[1][30]

The key drivers for utilizing a DGD system are many and include:

- Drill wells with a narrow pressure window
- The use of engineered drilling fluid
- Improve wellbore stability
- Decrease the number of casing strings
- Improve well safety, better kick detection
- Eliminate the “pump and dump” practice
- Increase the rate of penetration (ROP)
- Improve recovery of hydrocarbons
- Improve cementation and casing stability
- Decreased NPT
- Increase of well control
- Reduced mud loss to the formation
- Less drilling mud required
- Widen the drilling window

- Drill wells at excessive water depths
- Drill wells in depleted reservoirs
- Drill wells at high target Depth (TD)
- Increase number of drilling rigs that can accommodate deep water drilling

A good way of discussing the benefits of a DGD system is to compare problems related to the riser system used in conventional drilling to the solutions provided by DGD. A conventional riser system for deep-water environments requires huge deck space and load carrying capacity for riser tubing, i.e. large drilling rigs are required. More mud to fill the riser, which delivers extra hydrostatic pressure, which lowers the ROP, which reduces the well integrity, which requires more casing strings, etc. Increasing the size and cost of the drilling rigas well as costs on equipment and disposable tools. Limited personnel safety due to the slow reaction time needed to shut the well if a problem occurs. All this will increase the NPT, and the total operation costs can hit the roof. By utilizing a series of DGD systems, all of these problems is either minimized, eliminated entirely, or turned into an advantage.

The benefits for DGD are related to each other, by improving one thing, a series of other things benefit from the improvement. This means that a DGD system will ultimately improve safety and reduce costs with specialized techniques and surface/subsea equipment. The following casing example provides better understanding of the situation.

Significantly reducing the hydrostatic riser pressure in a deep-water well allows longer open-hole drill sections to be drilled before reaching the depth at which a casing must be set to avoid exceeding the fracture pressure of the formation. Optimal circulation rate in conventional single gradient drilling give high ECD measures, and reach the fracture pressure gradient much faster, because the hydrostatic pressure of the drilling fluid is much higher. All DGD operations decrease the hydrostatic pressure by lowering the weight of the drill fluid in the riser. Either by drilling top-hole sections without a riser (RMR) or fill the riser annulus with drilling fluid close to seawater density, and then use DGD components to return drilling fluid to the surface. This little adjustment of the system provides, more or less, all the benefits listed in the beginning of this section.

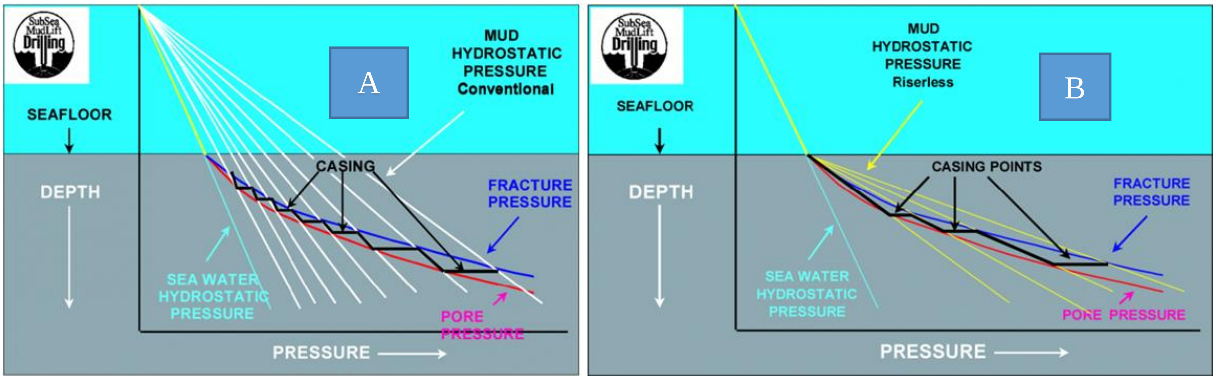

Figure 5.1 A - Conventional Casing Requirements. B - Riserless Casing Requirements[29]

5.2 Challenges

The main challenges of DGD are:. [1][2][10]:

- Limitations
- Initial cost of equipment
- U-Tube effect
- DGD Well Control
- Rig modifications
- Conservative industry

The industry have limited information and experience when it comes to DGD. The slow adapting, but also fairly new concept, has seen mostly theoretical and few practical applications so far. Compared to the amount of wells being drilled in the world, very few are drilled with a dual gradient system. This results in limited experience of personnel, few commercial DGD products, and less modified equipment. The solution would be to provide more funds for testing, modification and research.

A DGD system also require additional rig components than conventional drilling, and rig modifications is necessary to accommodate the new equipment. These modifications can be very costly. The same applies for well control; a change in the system requires change in the well control procedures. Well control procedures must include all stages of drilling. From initial planning to production of hydrocarbons. A new well control procedure must be made for all the components that make up the DGD system. This is to prevent blowouts, and the necessity to prevent other risks.

The oil and gas industry is a conservative industry, which makes it less receptive and slow in implementing technical changes and developements. Drilling personnel need to be trained, which require people to be open for new ideas. As of today, there is an excess of older generations in the industry, which over the years have become more stubborn and less receptive to new methods of drilling. For overall success of the new technology, knowledge and awareness between personnel is essential.

5.2.1 U-tubing

One of the most challenging effects in DGD is the U-tube phenomenon. U-tubing can go from being an event with no impeccable outcome with good well control, to being catastrophic for the well dynamics by marginally changing parameters affecting thē DGD system. Drilling with a conventional single gradient system the hydrostatic pressure is equal in the drill pipe and the annulus. When drilling with a dual gradient system a pressure imbalance occurs, naturally the heavier fluid in the drill pipe wants to create equilibrium in the hydrostatic head, and therefore makes the more dense fluid to freefall and u-tube into the annulus. During circulation, mudlift pumps create the equilibrium by pumping returns to the surface. However, when a connection is made, the rig pump circulation rate needs to decrease, putting the circulation rate below the mud freefall rate.[30]

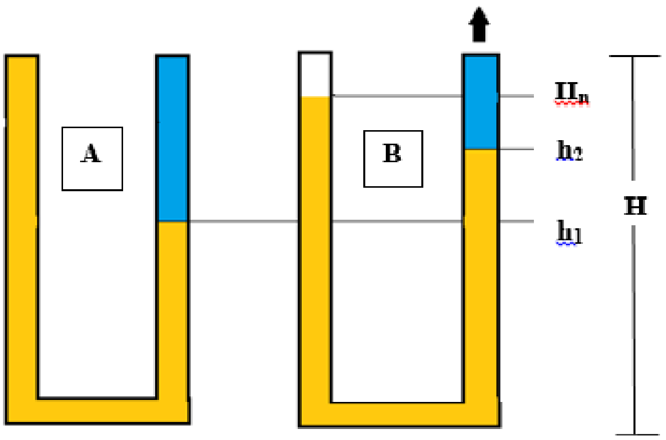

Figure 5.2 Simple illustration on the u-tube effect in an <u>open system</u>. The figure is missing some information: Left column – drill pipe, right – annulus, BHP and parameter description. The heavier mud in beige and the lighter in blue. A: Imbalance of pressure. B: Mud freefall, U-tubing.[30]

The U-tube effect while drilling with riserless or limited riser operations by usage of a subsea pumps occurs in a closed system. Usually a heavier mud is used during DGD operations in a closed system. This creates a higher hydrostatic pressure inside the drill-string compared to the hydrostatic pressure inside annulus when maintaining a wellhead pressure equal to the hydrostatic pressure of the seawater. In order to create equilibrium in the system, the fluid level in the drill-string will drop until the hydrostatic pressure from surface to sea floor inside the drill-string is equal to the hydrostatic pressure of the seawater (surface to sea floor), when the system is at rest (static).[30]

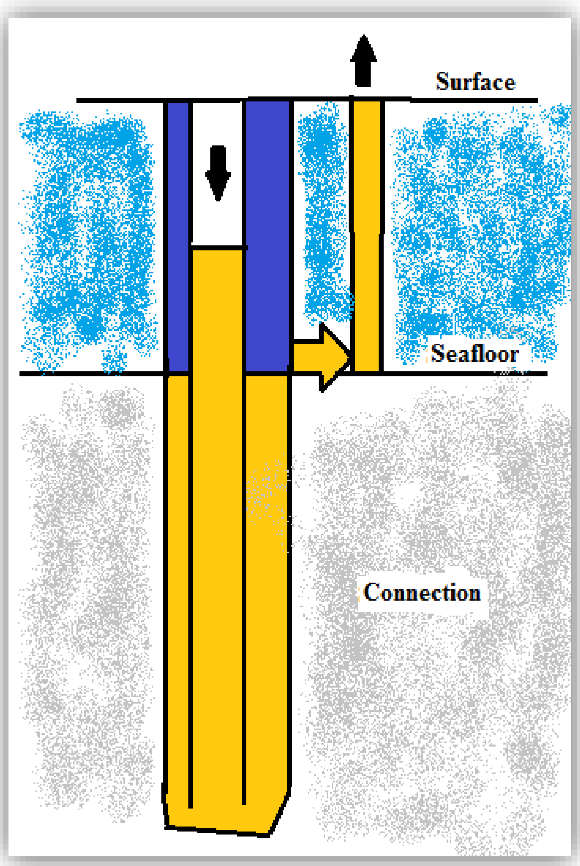

Figure 5.3 During circulation[30

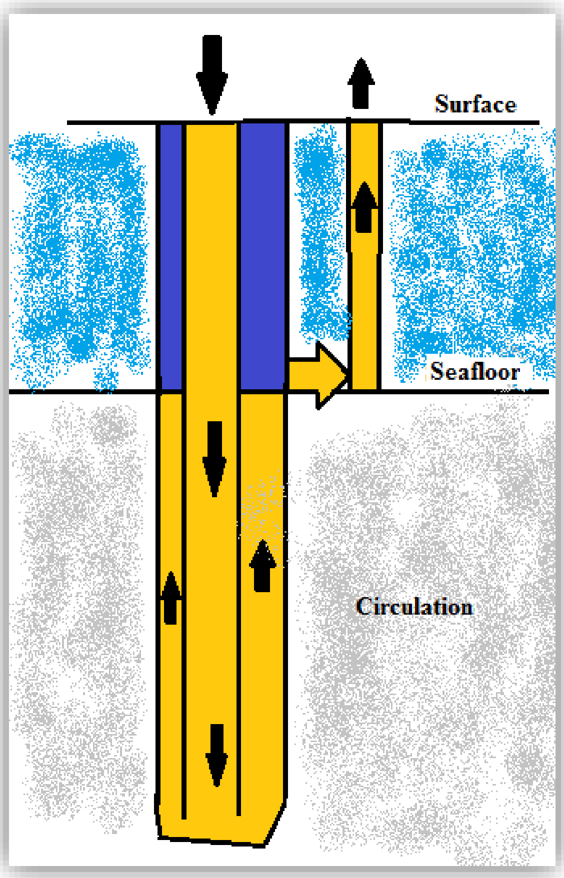

Figure 5.4 U-tube effect in closed system[30]

Dynamic equilibrium is used to determine the transient flow rate and mud level in the drill-string. U-tube calculations is as follows[1]:

$$0.00981\rho_m(D_w - h_x) - \Delta P_{f,ds} - \Delta P_{f,ann} - \Delta P_{bit} - \Delta P_{acc} - P_i = 0$$

$$\Delta P_{acc} = (1.10 * 10^{-4})\rho_m \frac{v^{n?1} - v^n}{\Delta t}$$

Fluid level drops at an increased rate in the start of the U-tube and then gradually decrease when final level is reached. A maximum drop of the mud level in the drill-string is calculated from[1]:

$$h_{max} = D_w - \frac{P_i}{0.0981\rho_m}$$

If the subsea pump pressure is maintained equal to the hydrostatic pressure of the seawater, a simplified equation is made[1]:

$$h_{max} = D_w \frac{(\rho_m - \rho_{sw})}{\rho_m}$$

The U-tube effect can then be found[1]:

$V = (drillpipe\ Capasity)(L - H)$, where

$H = \frac{\rho_{sw} * L}{\rho_m}$.

h_{max}	=	Maximum mud level drop (m)
h_x	=	Current mud level (m)
H	=	Height of mud in drill pipe from seabed, where equilibrium is reached (m)
L	=	Riser length (m)
V	=	Volume of displaced mud (m^3)
D_w	=	Water depth (m)
P_i	=	Subsea pump pressure (bar)
ΔP_{bit}	=	Bit pressure loss (bar)
$\Delta P_{f,ann}$	=	Annular friction pressure loss (bar)
$\Delta P_{f,ds}$	=	Loss of inner drill-string friction pressure (bar)
ΔP_{acc}	=	Acceleration pressure loss (bar)
u^{n+1}	=	Fluid velocity at time n-1 (m/s)
u^n	=	Fluid velocity at time n (m/s)
ρ_m	=	Mud density (s.g)
ρ_{sw}	=	Seawater density (s.g)

Δt = time interval (s)

The equations are derived from calculations of the BHP during circulation and when static. This is found in the appendix.

Parameters affecting the U-tube effect[34]:

- Water depth
- Well depth
- Mud density
- Mud viscosity
- Inner diameter (ID) of the drill-string
- Size of bit nozzle

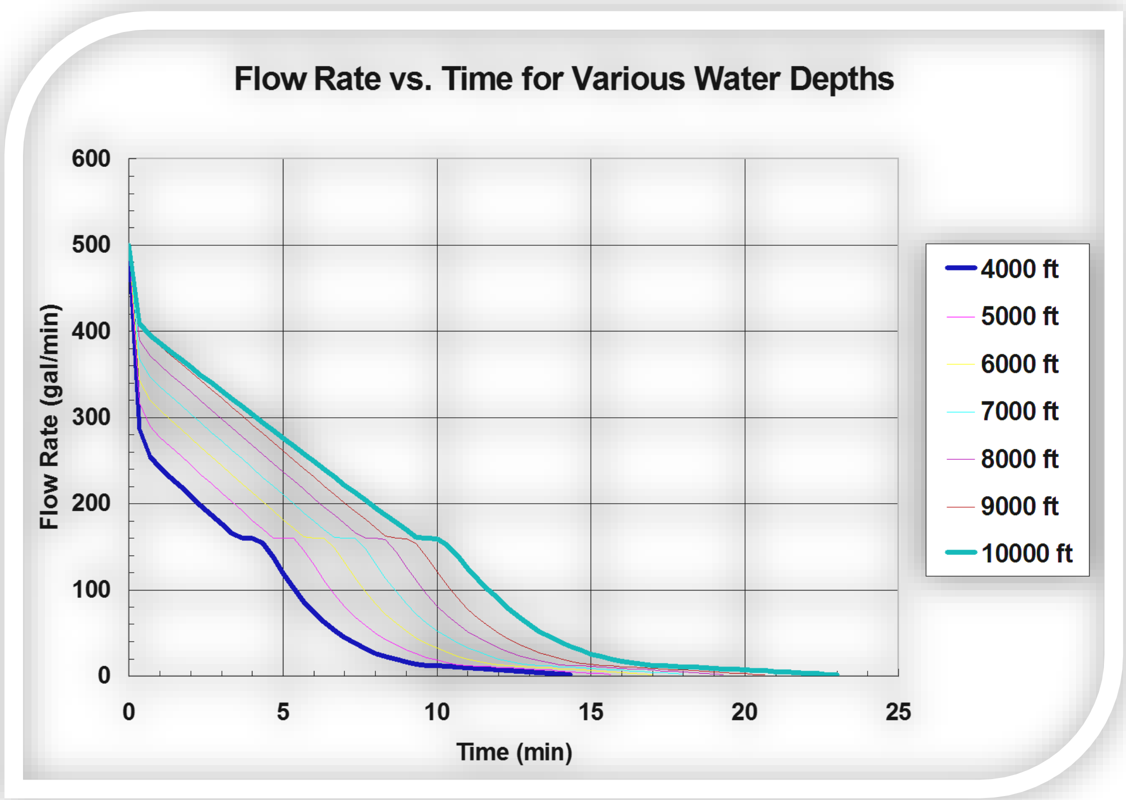

Figure 5.5 U-tube rate as a function of time for various water depths[34]

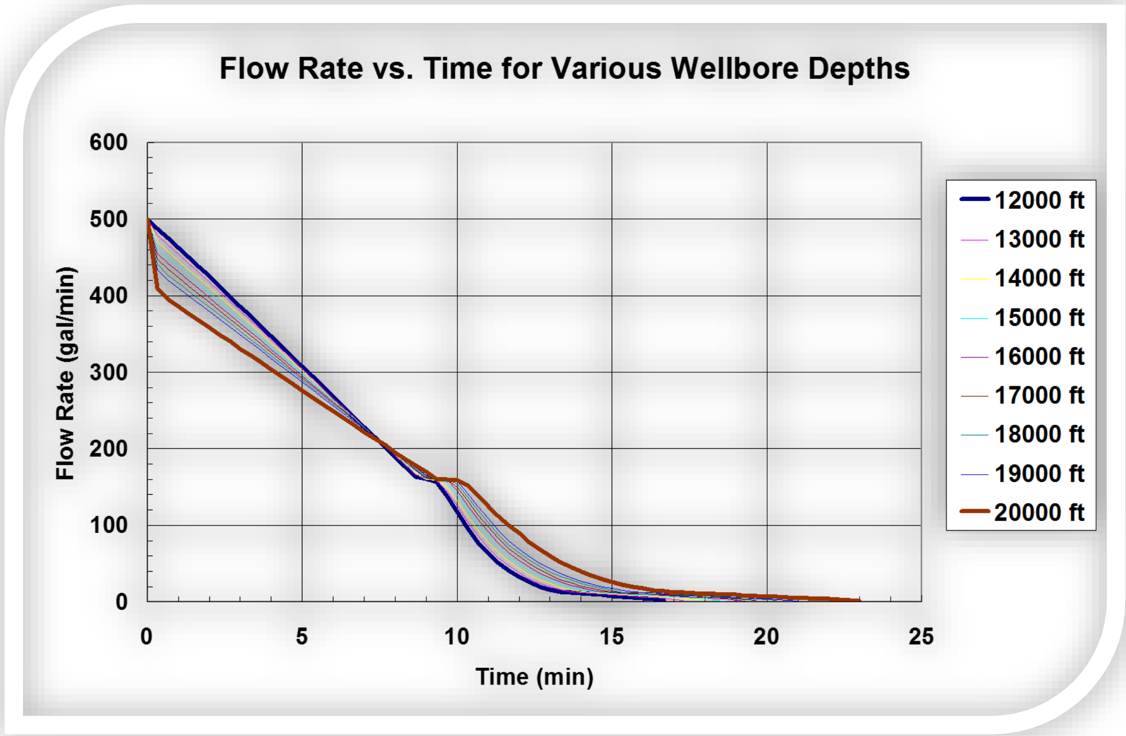

Figure 5.6 U-tube rate as a function of time for various well depths[34]

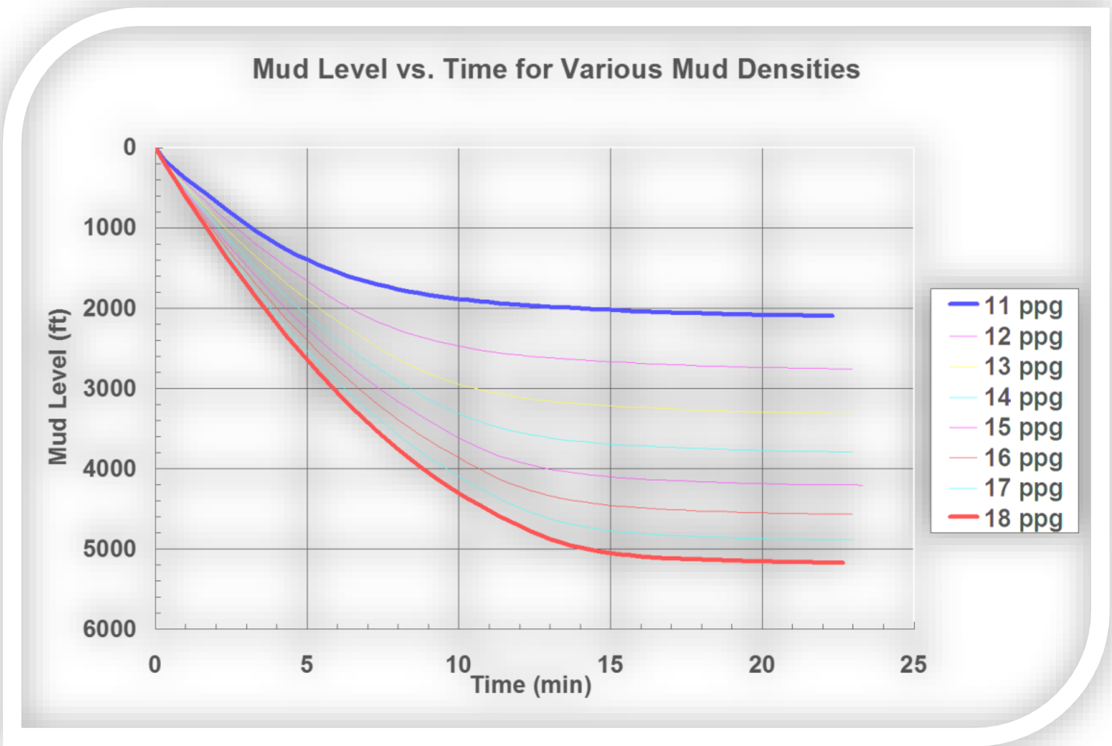

Figure 5.7 U-tube effect as a function of time for various mud densities[34]

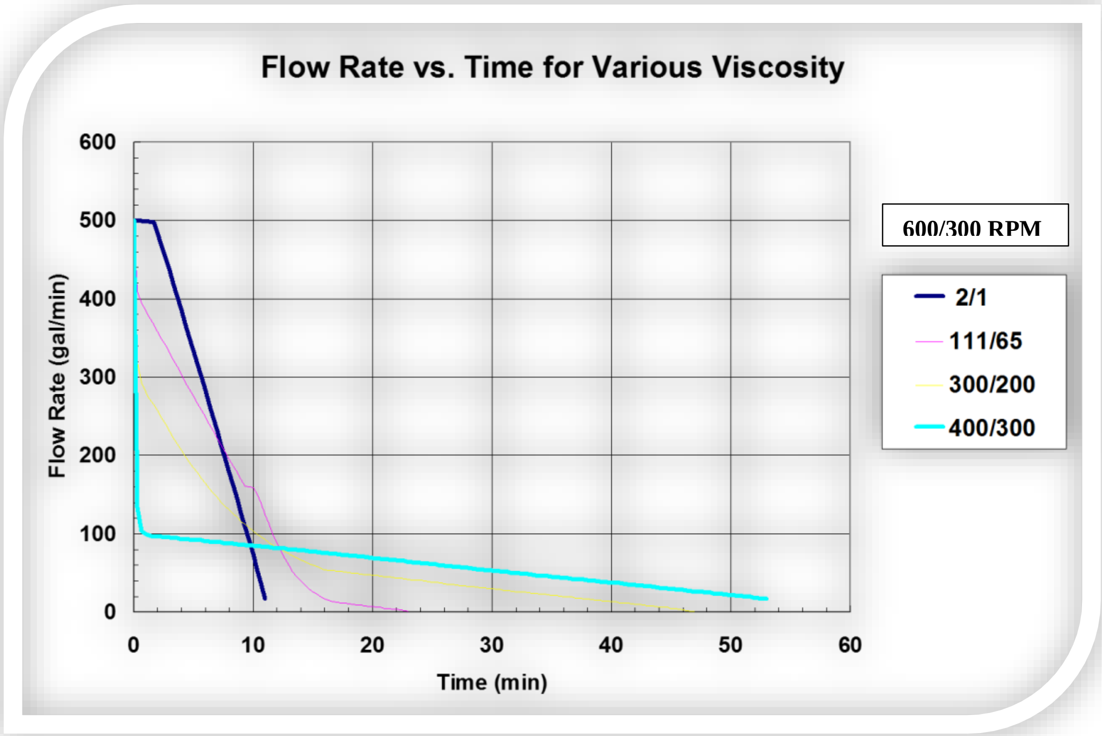

Figure 5.8 U-tube rate as a function of time for various mud viscosities[34]

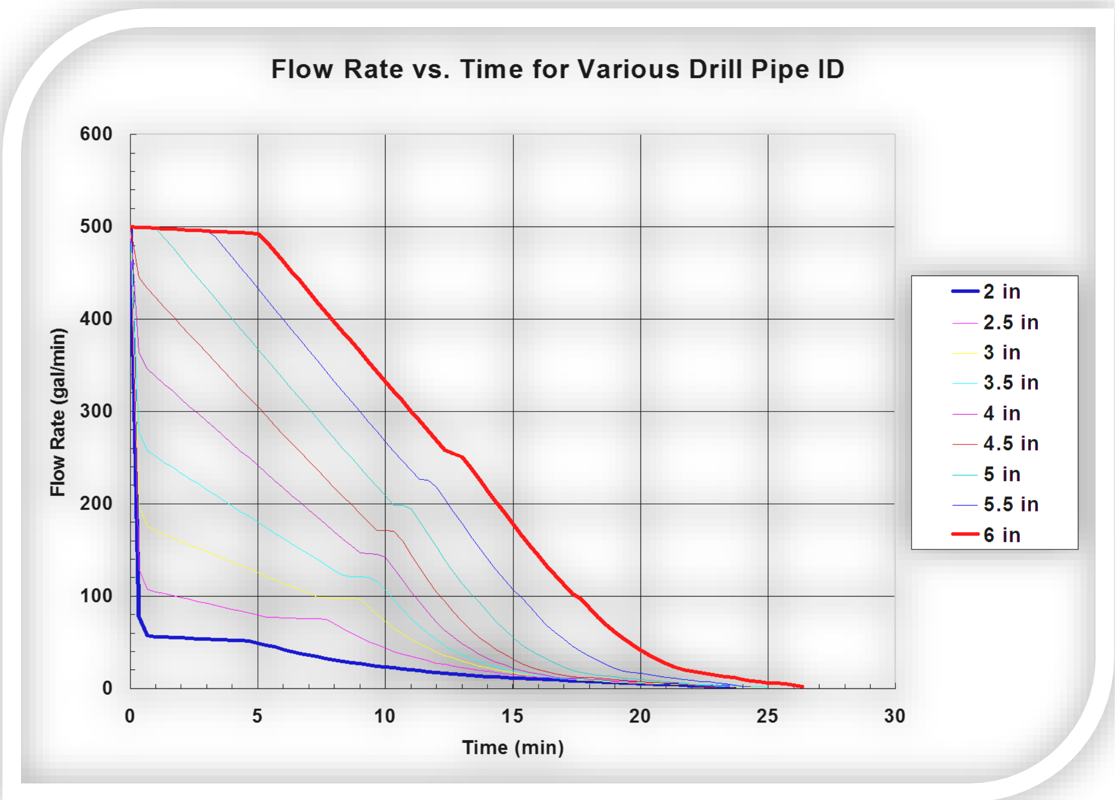

Figure 5.9 U-tube rate as a function of time for various ID drill pipe sizes[34]

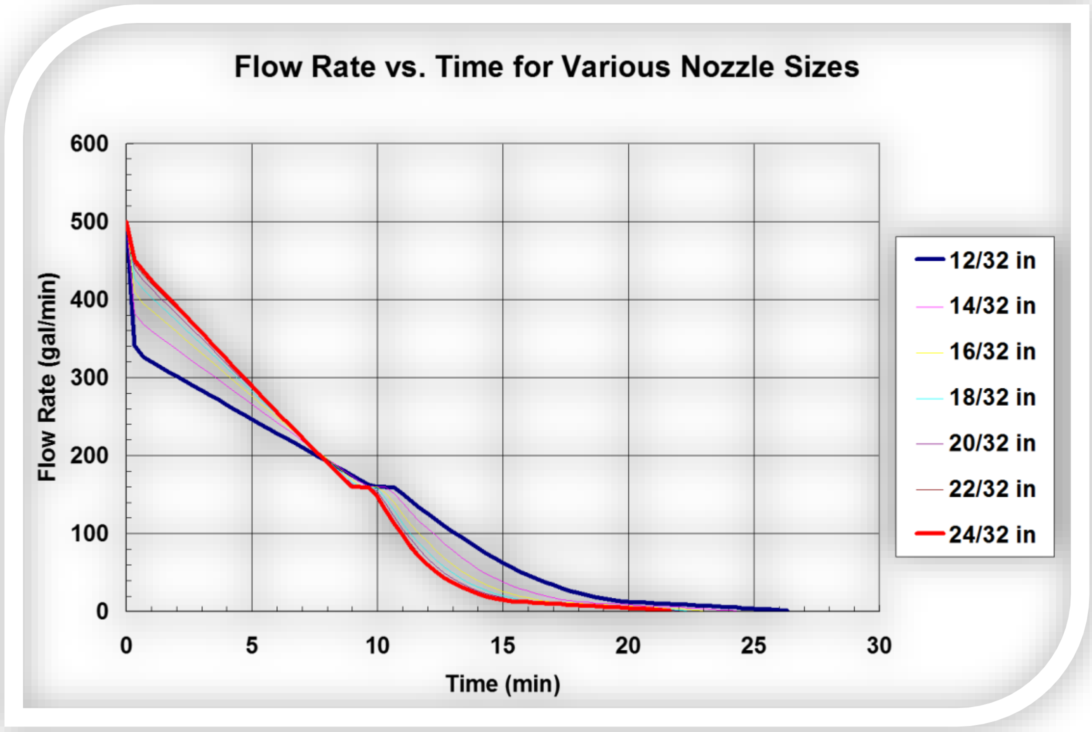

Figure 5.10 U-tube effect as a function of various bit nozzle sizes[34]

Figures 5.5 to 5.10 give visual understanding of how the parameters affect the U-tube effect. Notice how flow rate in some variables reaches 500 gallons per minute and the effect lasting well over 20 minutes. A solution to the U-tube effect is the DSV (Drill String Valve, section 4.7) located in the BHA. For operations without the use of DSV, will involve NPT until the U-tubing is static. Parameter optimization is then the key solution. How parameters affect the U-tubing effect is summarized in table 1.

Parameter <u>**Increase**</u>	**U-tube rate**	**Fluid level in drill pipe**	**Time to equlibrium**
Water depth	Increase	Decrease	Decrease
Well depth	Decrease	No change	Increase
Mud density	Increase	Decrease	Decrease
Mud viscosity	Decrease	No change	Increase
ID of drill pipe	Increase	No change	No change
Bit nozzle size	Increase	No change	Decrease

Table 1 Parameters affecting the U-tube effect[34]

5.2.2 Challenges during connection operations[2]

When rig pump is put to halt and circulation is stopped for connection operations, a pressure drop put the well in an underbalance pressure state before stabilizing. After a completed connection operation, the circulation is continued. This will put the well in a rapid pressure increase before stabilizing. Each connection is commonly done every 30m, which repeatedly expose the formation to these rapid pressure changes. Minimizing pressure variations exerted in the wellbore is one of the key drivers for developing a DGD system[2].

Problems that can occur during a connection procedure:

- Connection kick and formation collapse
  - The pressure drop exerted in the well from stopping the circulation may cause an influx of formation fluid into the wellbore. This is called a connection kick. The same pressure underbalance may cause the formation to collapse, which may cause the drill pipe to be stuck in the well.
  - Keeping a constant BHP provides a solution to this; open hole DGD system.

- Formation fracturing
  - When circulation is continued, the increased hydraulic pressure in the wellbore may exceed the fracture pressure of the formation. Fracturing the formation will contaminate the surrounding area and result in lost circulation.
  - The fracture pressure gradient for the well will decrease if fracturing initially occurs.

- Differential sticking
  - High wellbore pressure compared to low formation pressure in highly permeable formations with use of mud with a nearly impermeable filter cake may cause the drill-string to be stuck against the wellbore wall. High wellbore pressure during connection may be caused by high density drilling fluid.

- Slugging
    - Cuttings and debris will have time to settle and may change the properties of the mud, which affects the key drivers for the chosen mud. If the connection is not finished within the proper time margin, the returning debris can entomb the still-sting and generate a stuck pipe.
    - A prevention for this to happen is to circulate most of the debris out of the wellbore before making the connection.

Chapter 6

6 Parameter optimization and suggestions

To decrease the NPT when drilling a well, connection operations should be done as fast as possible. The previously discussed U-tube effect occurs each time the circulation stops. To increase the rate of the connection operation we need to decrease the time of the U-tube effect and still maintain a constant (fairly) BHP. Several DGD parameters affect the rate of the U-tube effect. Some parameters have already been addressed in section 5.2.1. Further discussion and optimization of the lighter fluid density and shut down pump rate, with respect to a fixed number of wellbore parameters, is done in this chapter.

6.1 Parameters affecting DGD

Section 5.2.1 and Table 1 show how an increase in some parameters affect the U-tube effect. Other parameters to take into consideration is the diameter of the riser and annulus, riser height, friction coefficient for drill-sting and annulus, riser fluid, mud volume flow and flow rate.

6.2 Choice of lighter liquid density

To increase the U-tube rate (shortening the time of the U-tube effect), the height of which the lighter fluid moves in the riser during a connection is essential. This can be done by alternating the lighter fluid density to which the change in riser level during connection is minimized.

During circulation, the BHP is a fixed value, say 450bar, and the change in riser level when changing the lighter fluid can be found by:

Old fluid:

$BHP = \rho_m g h_1 + \rho_w^1 g(H-h_1)$

New fluid

$BHP = \rho_m g h_2 + \rho_w^2 g(H-h_2)$

Where:

H	= the riser level
h_1	= static height of old fluid in riser
h_2	= static height of new fluid in the riser
ρ_w^1	= density of old lighter fluid
ρ_w^2	= density of new lighter fluid
ρ_m	= density of heavy fluid

And then combining the two:

$$h_2 - h_1 = \frac{\rho_w^2 - \rho_w^1}{\rho_m - \rho_w^2}(h_1 - H)$$

This is true for all if;

$$\rho_w^2 \leq \rho_w^1 \,, h_2 - h_1 \geq 0$$
$$\rho_w^2 \geq \rho_w^1 \,, h_2 - h_1 \leq 0$$

This means that the change in riser level are decreasing when lowering the mud density of the lighter fluid, and increasing when using a higher density mud. Lowering the mud density to where a stable BHP is maintained, and the riser level is somewhere in the middle of the riser length, is then a key factor to choose an optimal mud density for the lighter fluid.

To choose an optimal density for the lighter fluid with a given set of wellbore parameters the lighter fluid must satisfy the BHP during circulation and connection.

The BHP during circulation:

$$\overline{BHP} = \rho_m g H + F_a Q^2 + \rho_m g l_c + \rho_m g (h_r - l_c)$$

The BHP during connection:

$$BHP = \rho_m g H + \rho_m g l_n + \rho_w g (h_r - l_n)$$

With a fixed BHP, flow rate of main pump, riser fluid level, and wellbore coefficients the ρ_w is:

$$\rho_w = \frac{BHP - \rho_m g H + F_a Q^2 + \rho_m g l_c}{g(h_r - l_c)}$$

Where:

ρ_w = lighter drill fluid

ρ_m = heavy drill fluid

H = riser length

h_r = height of lighter fluid in riser

l_c = riser fluid level during circulation

l_n = riser fluid level during connection

Q = flow rate of main pump

F_a = annulus friction coefficient

The choice of ρ_w during a connection,

$$(\rho_m - \rho_w) g l_n \geq F_a Q^2, \qquad \text{for} \qquad l_n \in [0, h_r - l_c]$$

need to satisfy the BHP for circulation:

$$(\rho_m - \rho_w) g (h_r - l_c) \geq F_a Q^2$$

Where optimal lighter fluid density is the minimum possible value of $(\rho_w - \overline{\rho_w})^2$.

A series of simulations were done with trial and error, and the best ρ_w were chosen to be 620.8686 kg/m^3 at lc 475m.

6.3 Choice of shutdown flow rate for main pump

Shutting down the pump rate too fast result in a series of unwanted complications, and a too slow shutdown flow rate increase the time before a connection can be made, which increase the NPT. Finding an optimal shutdown flow rate for the main pump is therefore also essential for increasing the connection time.

Flow rate:

$$Q = Q_0 - aq_0t$$

Volume:

$$V = \frac{{Q_0}^2}{2aq_0}$$

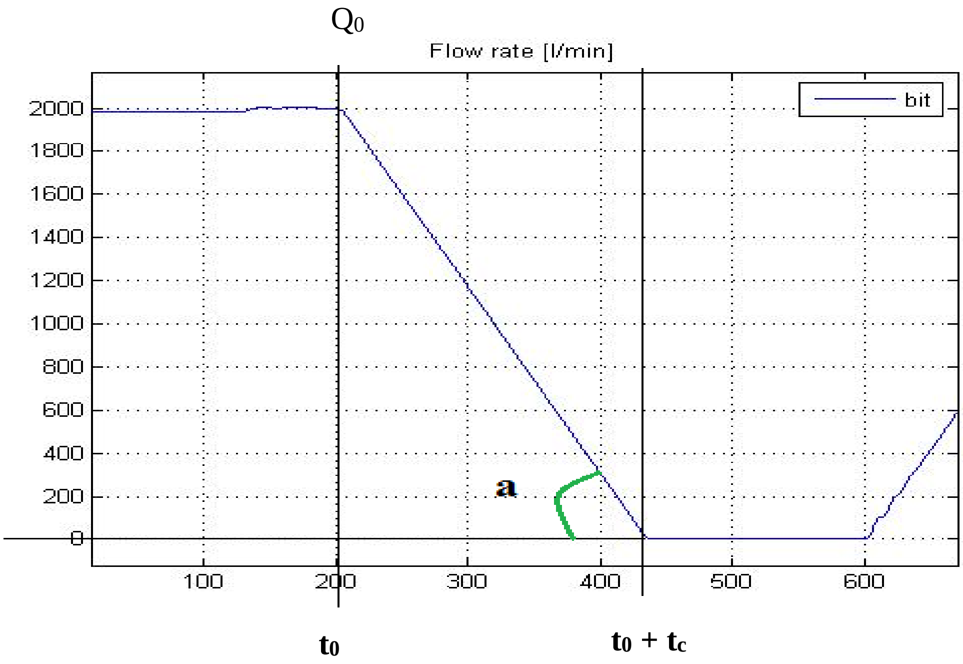

Figure 1 Shutdown flow rate example. From 2000 to 0 l/min over time interval [t_0, t_0+t_c]

Using the time interval in volume calculation:

$$V = \int_{t_0}^{t_0+t_c} Q dt$$

Together with wellbore parameters and constant BHP:

$$(\rho_m - \rho_w) l_{max} \geq F_a Q^2$$

Where max riser level is:

$$l_{max} = \frac{{Q_0}^2}{2 a q_0 A_r}$$

And a choice of a that derives the minimum value of $(a - \bar{a})^2$ possible can be suggested.

Chapter 7

7 Control Theory

When parameters for well characteristics is found or given, a control algorithm can be applied to the system in order to automate drilling procedures.

7.1 PID controller

A proportional-integral-derivate controller is a control loop feedback tool, used in 95% of all industrial control systems in general. A PID control is used to bring the operation conditions of a process to a predetermined reference value. It calculates an error value as the difference between a measured parameter and the desired set-point of the parameter. The controller then tries to minimize the error by adjusting the process through use of a manipulated variable and still maintain the set-point.

The error signal is given by:

$$e = r - y$$

Where:
$e = error\ signal$
$r = reference\ value$
$y = measured\ value$

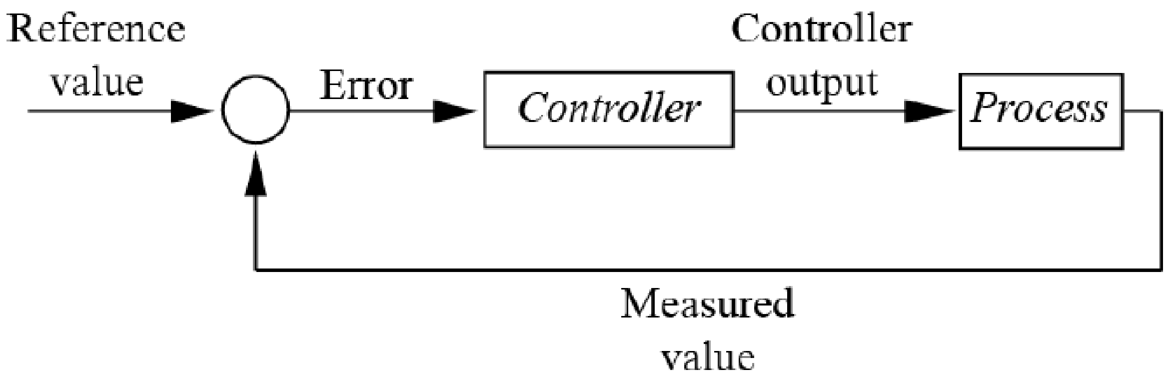

Figure 7.1 Linear error control[2]

The PID control algorithm consists of three distinct parameters, which the correspondent values, in simplicity, can be inferred in terms of time:

- Proportional (P): Depending on the present error. The controller output is proportional to the error input signal, which means that the changes in output is proportional with the present error value. Reference value is reached quicker with higher proportional gain. The proportional term is given by[2]?:

$$u = u_0 + K_p e$$

Where
$u = the\ controller\ output$
$u_0 = the\ input\ value$
$K_p = the\ proportional\ gain$

- Integral (I): Integration on the accumulation of past errors to reach the reference value quicker. The contribution is proportional to both the degree and duration of the error. It is the sum of all the prompt errors over time and provides the accumulated offset that previously should have been corrected. The integral term is given by:

$$u = K_p \frac{1}{T_i} \int_0^t e dt$$

Where:

$T_i = the\ integral\ time\ constant$

- Derivative (D): Prediction of future errors. It predicts system behaviour by determining the slope of the error over time and slowing down the change gain of the controller input. The derivative term is given by:

$$u = K_p T_d \dot{e}$$

Where:

$T_d = the\ derivative\ time\ constant$

The outcome of combining these three terms is a PID controller:

$$u = K_p e \frac{K_p}{T_i} \int_0^t edt + K_p T_d \dot{e}$$

The subjective sum of these three terms is used to automatically adjust operations via a control element. Such actions may include pump rate for rig pump and booster pump during drilling operations by controlling the shutdown rate during a connection. The terms are seldom used separately, however, for most applications the first two terms provide sufficient information, excluding the derivative term from the controller. Without the derivative term the controller is just a PI controller, where $T_d = 0$.[2][35]

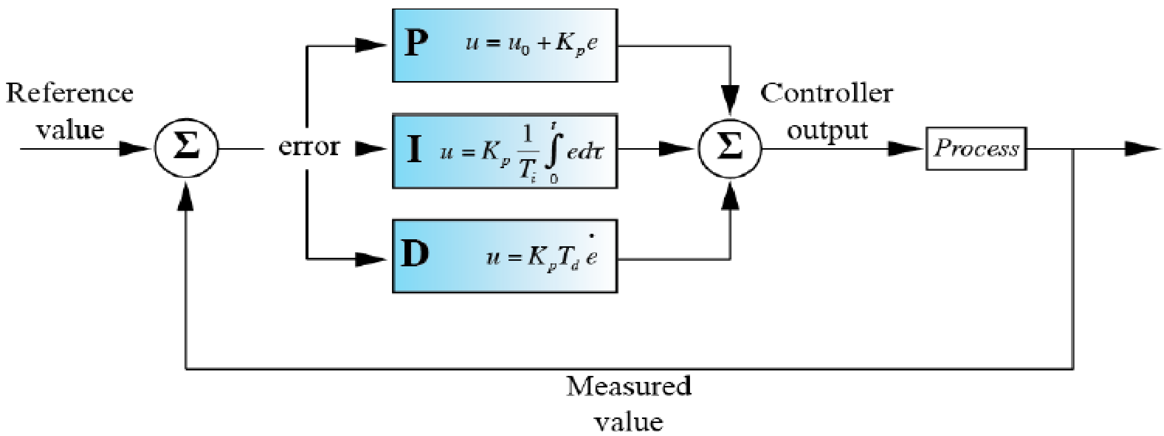

Figure 7.2 PID Controller[2]

When using a PID controller the reference value is always a constant value, which gives the controller no indication of the actual process. Disturbances affect the control loops and the controller can only correct the disturbances after the system output has been affected. If a process experiences a disturbance, v, or a change in the reference value, r, a feedforward (loop tuning) controller can be applied to improve the performance of the controller. A feedforward controller make corrections on the process to reduce the effect of a disturbance before is reaches the system output signal. A PID controller with a feedforward control is given by[2]:

$$u = u_0 + K_p e \frac{K_p}{T_i} \int_0^t e dt + K_p T_d \dot{e} + K_r \dot{r} + K_v v$$

Where:

$K_v = feedforward\ term\ for\ chang\ in\ the\ disturbance$

$K_v \dot{v} = feedforward\ term\ for\ changes\ in\ the\ reference$

A PID controller does not provide exact corrections without including a feedforward controller, which makes the feedforward controller almost always an addition to the feedback controller (PID controller).

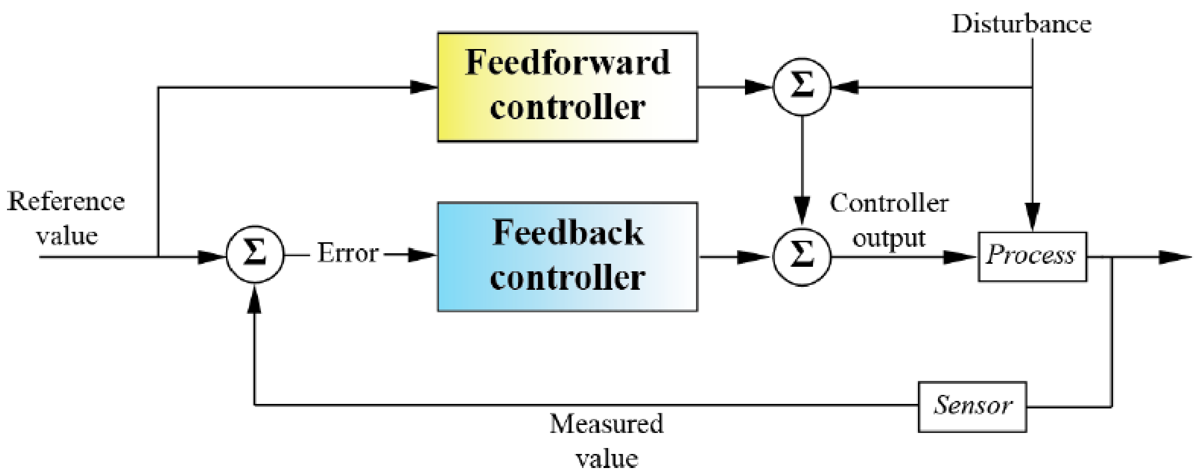

Figure 7.3 Feedforward Control[2]

It is important to tune the parameters in the PID controller for optimal performance. When constructing a PID controller, tuning can be done by use of software tools, the Zieger-Nichols method, Cohen-Coon method, or manually.

7.2 Kaasa's model for DGD[2]

A hydraulic model is needed to enable automatic control of the fluid system used during drilling operations. Several hydraulic models that differ significantly in complexity have been developed. One of the most complex models, Sinte-F, developed by the International Research Institute of Stavanger (IRIS) contains several parameters with minimal efficiency and is too complicated to be used in learning. Kaasa's model is more or less a simplified model primarily used for learning and understanding. Another simplified model is Kjell Kåre's Model, a 2-phase-model that includes another physical state in the operation.

Notice that simplified does not mean simple, and the overall complexity of these models is generally a downside. To include all aspects of the drilling fluid hydraulics, the complexity of the models require expert knowledge to operate. When drilling a dual gradient well, continuous change of conditions may prove all measurements insufficient to calibrate the parameters. In addition, the overall accuracy that is achieved is not greatly improving the operation.

Kaasa's Model simplifies the complexity by using basic fluid dynamics to describe to most important hydraulic aspects of DGD. Dynamic factors that does not greatly affect the system is neglected and only the major dynamic factors are left to play. To further simplify the model, Kaasa has removed dynamics that change its condition faster than what the control system can notice and react to. In addition, slow dynamics, which is easy to control from the feedback in the system, and parameters that are lumped together and impossible to differentiate are removed.

Kaasas model assumes a unified flow pattern throughout the whole length of the drill-string, as well as a uniform flow pattern in the whole length of the annulus. This way the well can be divided into two separate control volumes with different dynamics.

Based on the conservation of mass throughout the well and the isothermal equation of state, equations used in Kaasa's model are derived:

For drill-string:

$$\sum m_{in} - \sum m_{out} = \dot{m}$$

$$m = VP \rightarrow \dot{m} = \dot{V}P + V\dot{P}$$

$$m = \rho q \rightarrow \rho(q_{in} - q_{out}) = \dot{V}P + V\dot{P}$$

By density being a function of pressure and time,

$$\rho = f(P,T) \approx \rho_0 + \beta(P - P_0) + \alpha(T - T_0)$$

Linearizing the slope gives,

$$\rho = \beta\dot{P} \rightarrow \dot{\rho} = \frac{\beta}{\rho\dot{P}} \rightarrow \rho(q_{in} - q_{out}) = \dot{V}P + V\beta\dot{P}\rho$$

Which gives:

$$\dot{P} = \frac{\beta}{V}\left[q_{in} - q_{out} - \dot{V}\right]$$

This equation provides the pump pressure dynamics for the drill-string to be

$$\dot{P_p} = \frac{\beta_d}{V_d}\left[q_p - q_b - \dot{V_d}\right]$$

which is very simplified (absence of several factors), but still useful.

Since the total drill-string volume is considered constant, the choke pressure dynamics for the annulus is given the reverse flow pattern:

$$\dot{P_c} = \frac{\beta_a}{V_a}\left[q_b + q_{res} + q_{bpp} - q_c - \dot{V_a}\right]$$

Where[2]:

$$q_c = Z_c K_c \sqrt{\frac{P_c}{\rho_a}}$$

Where:

P_c = Choke pressure

P_a = Density of fluid in annulus

By applying Newton's 2nd law and conservation of mass to the equations for pump and choke pressure dynamics, and combining the two, the dynamic flow rate through the bit is found to be:

$$\dot{q}_b = \frac{1}{M}\left[\left(P_p - P_c\right) - (F_d + F_b + F_a)q_b^2 + (\rho_d - \rho_a)gh\right]$$

Where:

$$M = \left[\frac{m_d}{A_d^2} + \frac{m_a}{A_a^2}\right]$$

Where:

q_p = flow rate from the pump

q_b = flow rate through the bit

q_{res} = flow rate from reservoir

q_{bpp} = flow rate from back pressure pump

q_c = flow rate through the choke

Wellbore parameters:

β_d = bulk modulus of the drill-string

V_d = volume of drill-string

β_a = bulk modulus of the annulus

V_a = volume of the annulus

M = the integrated density per cross-section over the flow path

A_d = drill-string diameter

A_a = annulus diameter

F_d = srill-string friction coefficient

F_b = bit friction coefficient

F_a = annulus friction coefficient

ρ_d = drill-string fluid density

ρ_a = annulus fluid density

___

K_c = valve parameter

Z_c = valve opening

Chapter 8

8 Simulations

Several simulations were made prior to writing this thesis. Although the substance may feel like the opposite. To find the optimal input data with a given set of fixed wellbore parameters was primarily done by fail and error. This chapter includes PID simulations using Kaasa's model for DGD operations with suggested optimal input data.

8.1 MATLAB

Matrix Laboratory (MATLAB), developed by MathWorks and allows for matrix manipulation, plotting of functions and data, implementation of algorithms, creation of user interfaces and much more. Broadly used in the aspect of teaching and learning as well as in commercial industry and computer programming. Simulations made in this thesis is based on the MATLAB software[36].

8.2 Lighter fluid density with PID

On order to find the optimal lighter fluid density a series of simulations were made regarding the fluid riser level before a connection (during circulation):

Riser Level (m)	Density
25	988.1955
50	975.3302
75	961.8931
100	947.8452
125	933.1439

150	917.7426
175	901.5900
200	884.6297
225	866.7997
250	848.0313
275	828.2484
300	807.3664
325	785.2911
350	761.9173
375	737.1270
400	710.7872
425	682.7481
450	652.8397
475	620.8686
500	586.6134
525	549.8218
550	510.1996
575	467.4076
600	421.0496
625	370.6604
650	315.6904
700	189.2595

Table 2. Simulation results

The lighter fluid density in the riser were optimized to be about 621 kg/m^3 with the given wellbore parameters, and with a shutdown speed of 0.01 (200s) and riser area of 0.01m^2 and no booster or back pressure pump asserted on the simulations. This density might seem a bit low, and the dynamics of providing such a low density drilling fluid could be a negative factor. In addition, an increase in riser area could seem to simulate the same positive effects, as given in the figures below, for the need of a lighter fluid density that is heavier than provided in this thesis. The riser fluid should keep a density close to the density of seawater to avoid high hydrostatic pressure differences at the seafloor between the seawater and the riser fluid.

Parameter	Value
H	2000 m
h_r	1200 m
A_r	0.01 m^2
ρ_a	1580 Kg/m^3
ρ_d	1580 kg/m^3
β_d	$2e^9$
β_a	$1e^9$
V_d	$17m^3$
V_a	$48m^3$
M	$4.3e^8$
F_d	$5e^9$
F_b	$1e^9$
F_a	$2e^9$

Table 3. Wellbore Parameters

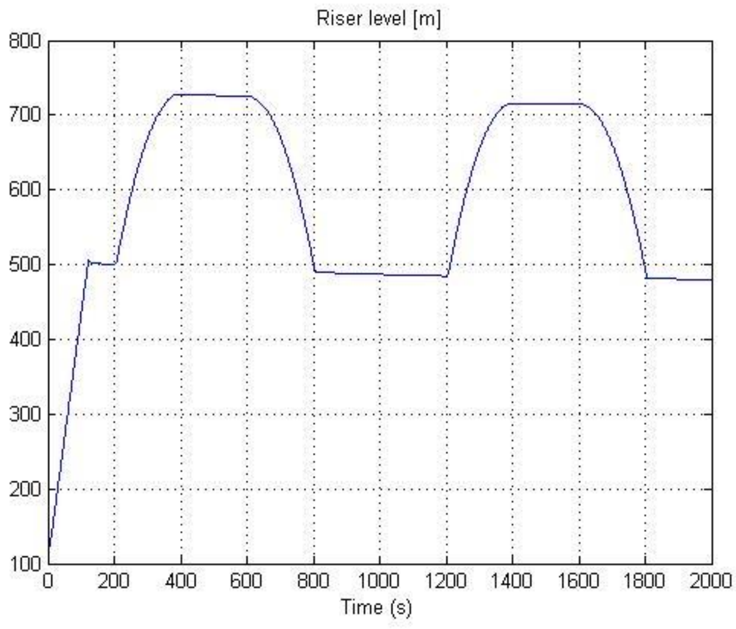

Figure 8.1 Riser level during a connection for lighter density fluid 620.8686 kg/m^3

Pump shutdown starts after 200 seconds into the simulation, at this time the U-tube effect is starting to affect the riser fluid level, which goes from 500m to725m. This is well within the maximum riser level at 1200m.

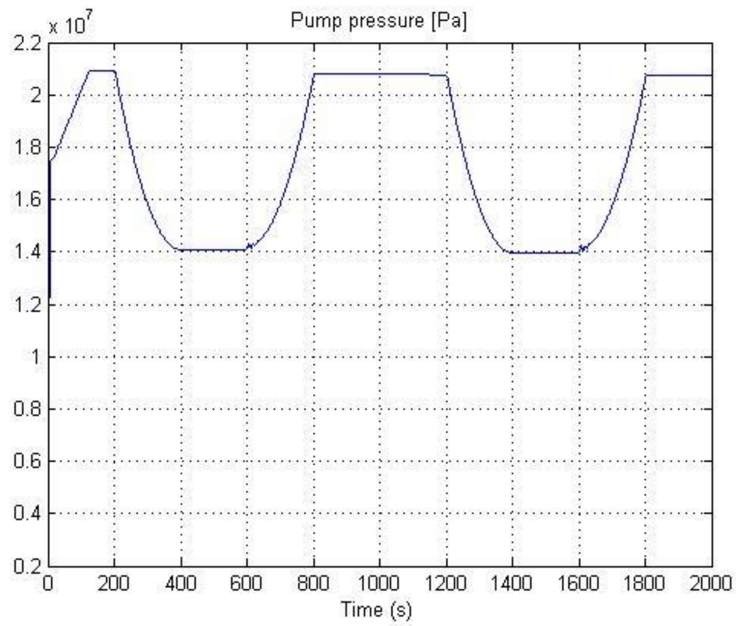

Figure 8.3 Pump pressure

When shutdown of the main pump the pump pressure gradually decreases to hydrostatic pressure inside the annulus and is static throughout the length of the connection, 400-600s.

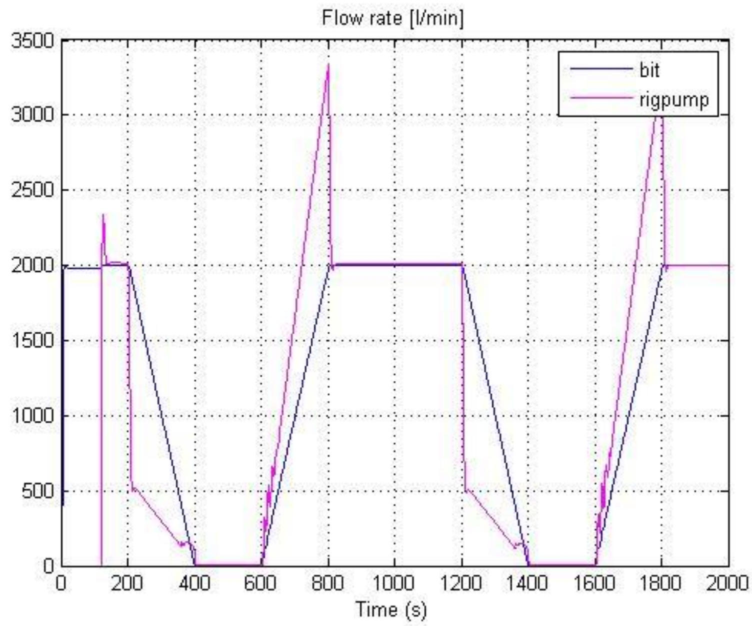

Figure 8.4 Flow rate through the bit and rig pump

The PID controller controls the rig pump so that the flow rate through the bit is maintained at the same decreasing rate. Circulation stops at time = 200s and connection can be made from 400 to 600s, and the circulation is up to normal circulation flow at 800s.

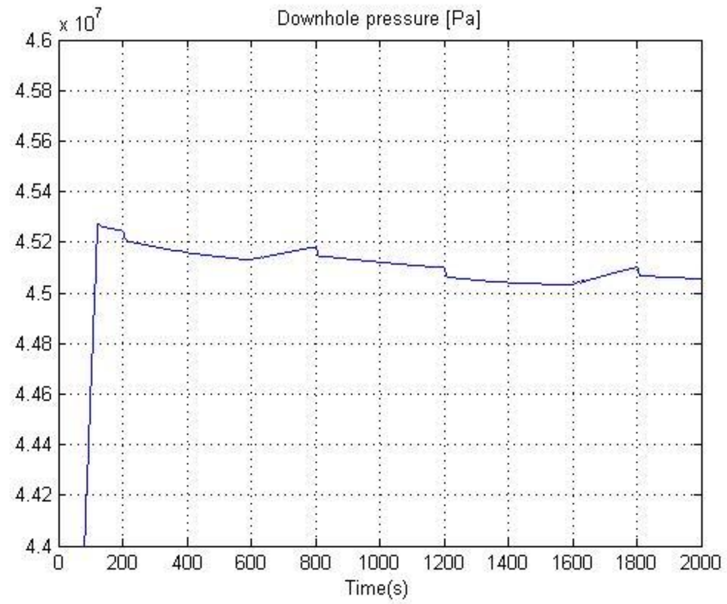

Figure 8.5 BHP during connection

The bottom hole pressure during connection is remained within the reasonable margin of ±2.5 bar for the 450bar reference value (circulation). This is a very good result, however the initial BHP of 452 bar at 200s when the shutdown operation starts may be considered a little high. but on the other hand it stabilizes at around 450 bar during the whole wellbore operation (circulation and connection).

8.3 Shutdown rate of pumps

A series of trial and error simulations were made to optimize the shutdown rate of mud pumps for an increase in the U-tube effect and shorter connection times. The same lighter fluid density was used, but what also was found is that a higher density fluid in the riser than what was optimized could prove to work better with increased shutdown speed if a back pressure pump was connected. This would however make the PID controller to increase the rig pump to almost maximum capacity to compensate for the extra flow variable exerted by the back pressure pump.

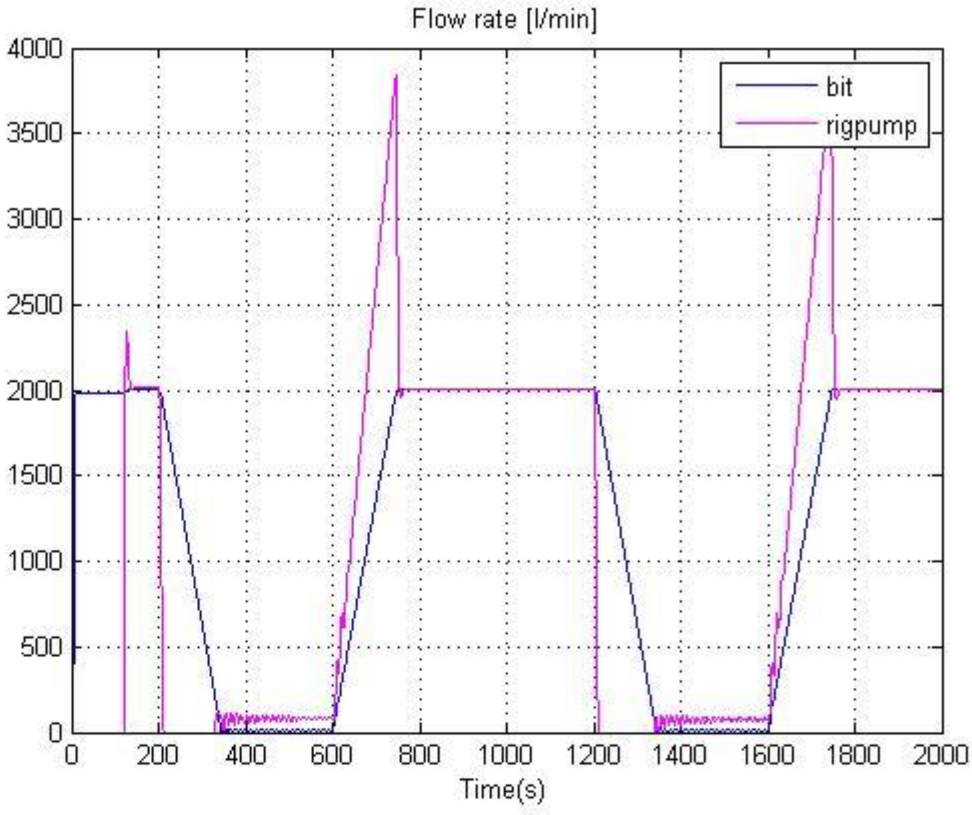

Figure 8.6 Flow rate with optimal shutdown speed

An increase in the shutdown speed were optimized to increase the U-tube rate. The suggested value is 0.0139, 150 s. It can be seen that a connection can now be done only 150s after the initial shutdown of circulation. The PID controller pushing the flow rate of rig pump to 3800 l/min to compensate for the increased start-up speed. This is however within the max flow rate of the rig pump.

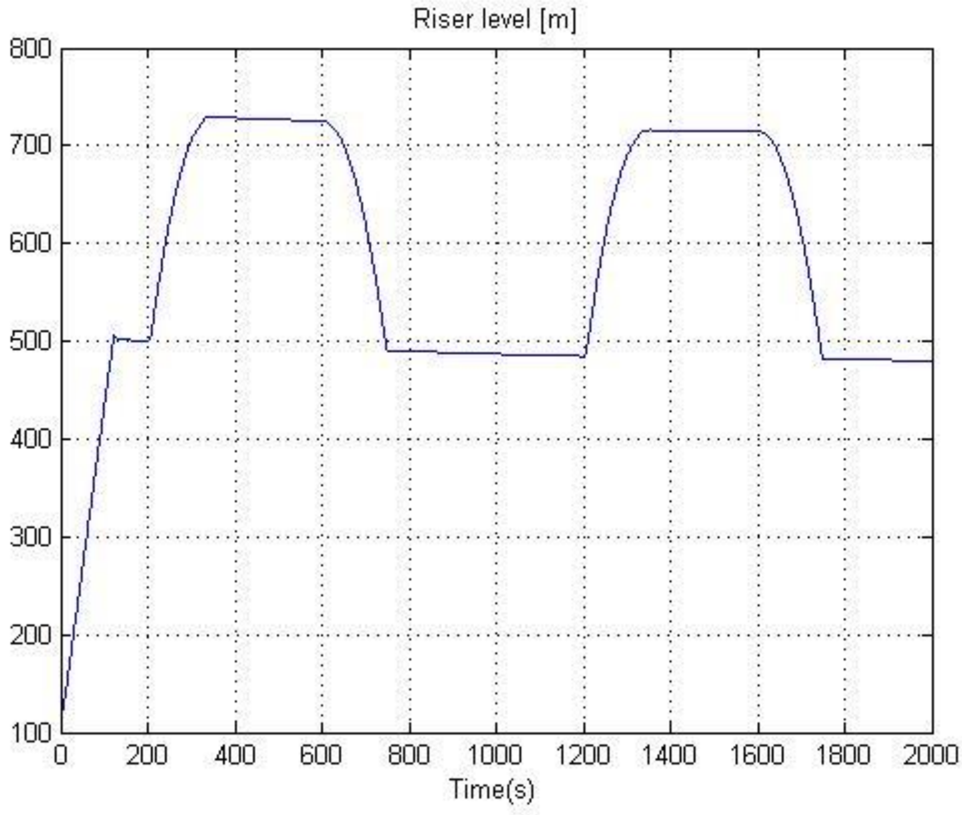

Figure 8.7 Riser level during connection and circulation with optimal lighter fluid density and shutdown rate

The riser dynamics does not seem to be affected with an increased shutdown speed of the suggested value. However, if the shutdown rate were increased slightly more, the simulations would show a peak in the top riser level during connection and at start-up of circulation.

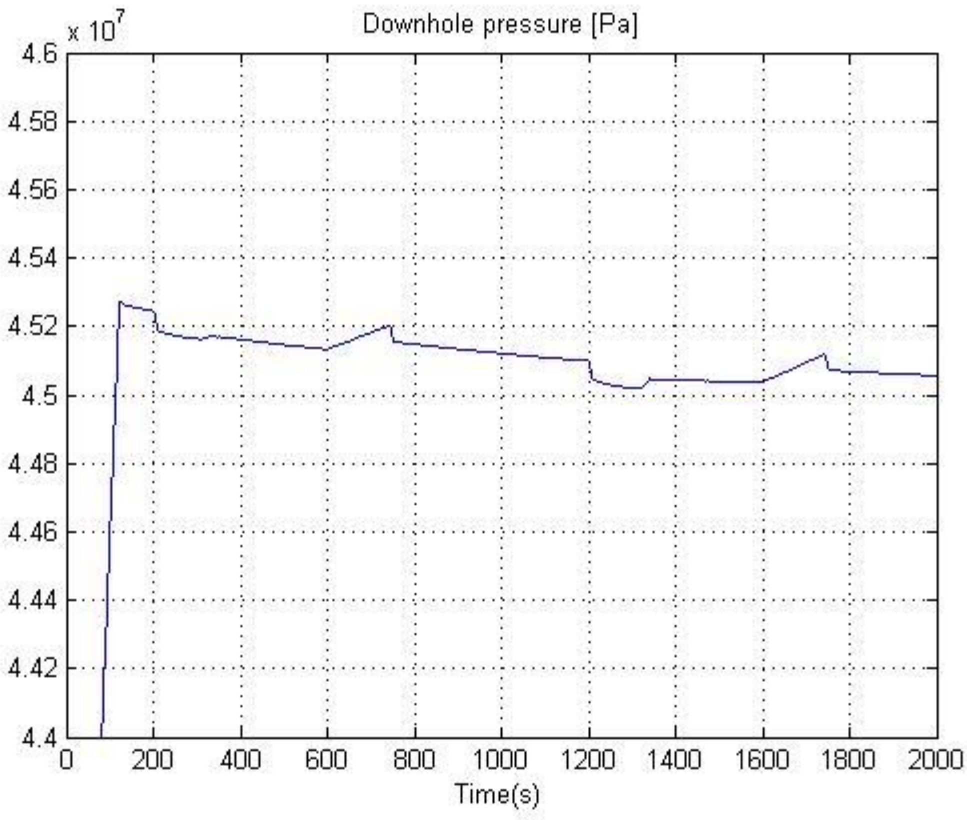

Figure 8.8 BHP with optimized shutdown speed

Slight variation in BHP with a faster shutdown speed. A small drop in BHP can be seen when shutdown of circulation starts, and a small increase when starting to circulation again. The BHP is however maintained at 450 bar with a ±2.5bar variation, which is allowed.

8.4 Simulations with back pressure pumps

This section is to show a back pressure pumps can be utilised to create a stable BHP with faster shutdown speed, with the use of an increased density of the riser fluid compared to the suggested value given in this thesis. The shutdown speed is now a little more than 100s, lighter fluid density 790 kg/m^3 and the back pressure pump operates a flow rate of 800 l/min.

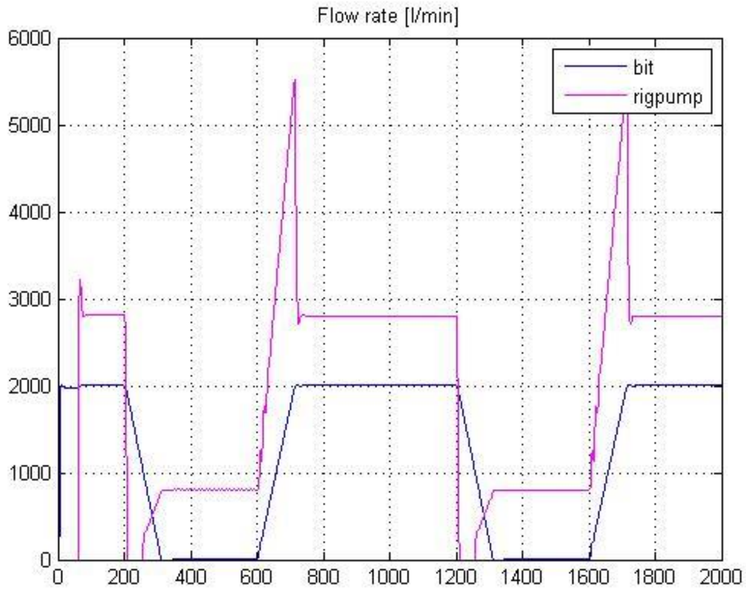

Figure 8.9 Well flow rate with BPP

Increased shutdown speed with more than 50% compared to the simulations made with optimal density. Flow rate for the rig pump reaches 5500 l/min, this is however within the margin of what rig pumps should deliver.

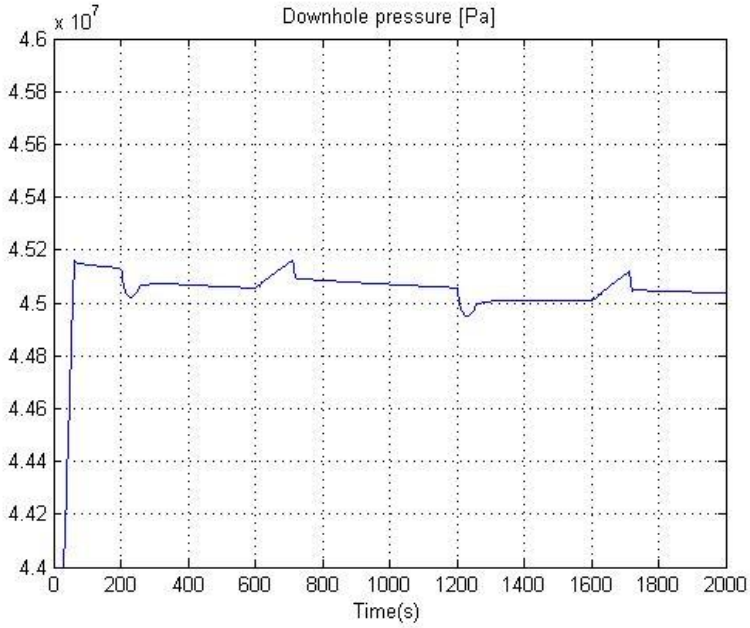

Figure 8.10 BHP simulation with BPP

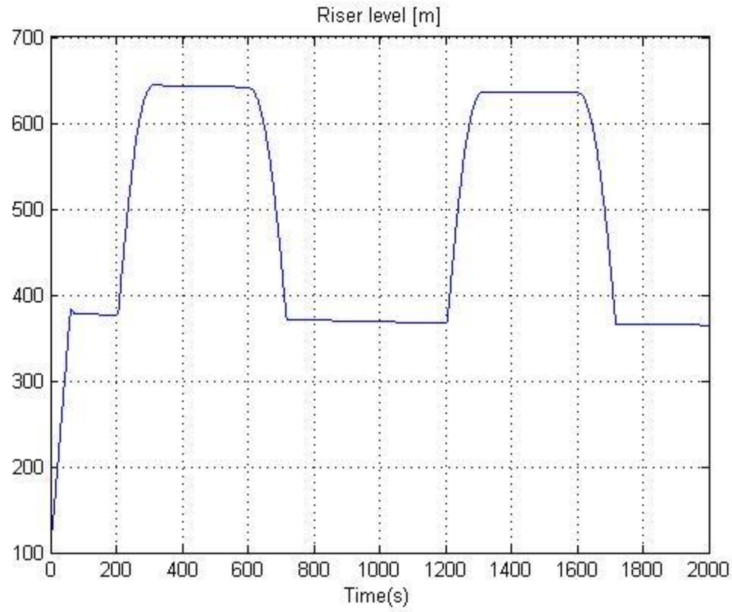

Figure 8.11 Riser level with BPP

Both BHP and riser level does in this case show a good model for a DGD operation

8.5 Booster Pump

A booster pump of flow rates up to 1000 l/min for the optimized density of the riser fluid and shutdown speed were also added to the simulations. All level of flow from the booster pump showed little to no change in the DGD system. The 1000 l/min booster pump simulation showed a small increase in the BHP stability with lower variation from the 450bar reference value. No other significant changes were found, except for the PID controller trying to compensate for the booster pump with the rig-pump at 1000 l/min. All well parameters are the same all the way through.;

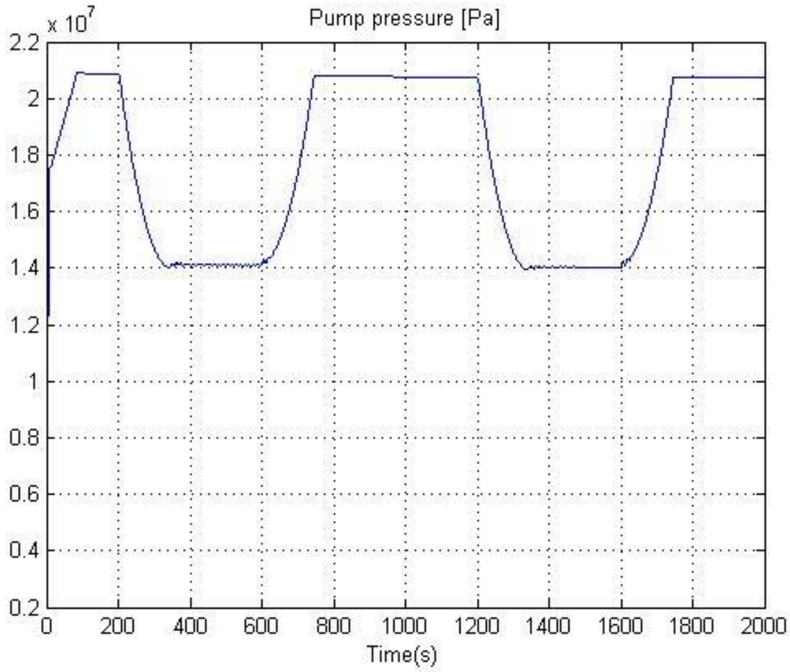

Figure 8.12 Pressure profile with booster pump at 1000 l/min

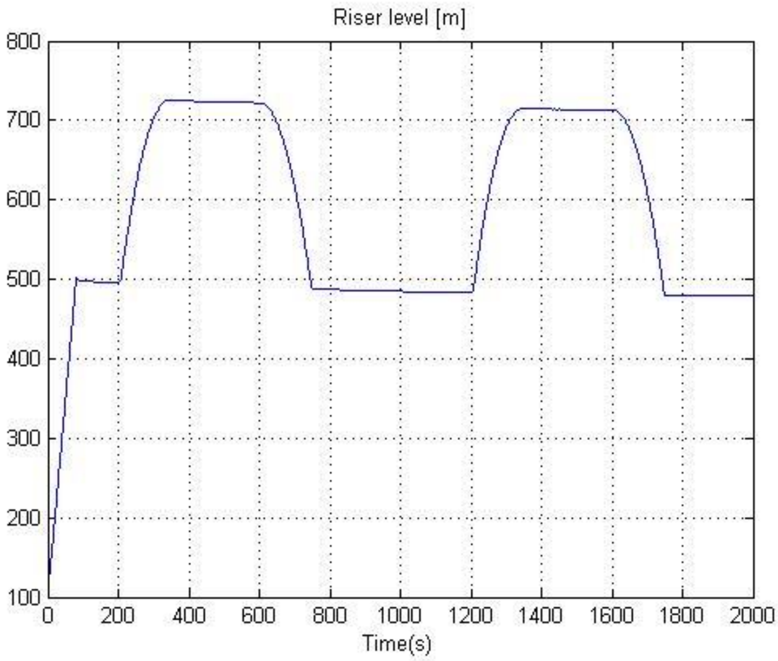

Figure 8.13 riser fluid level with booser pump

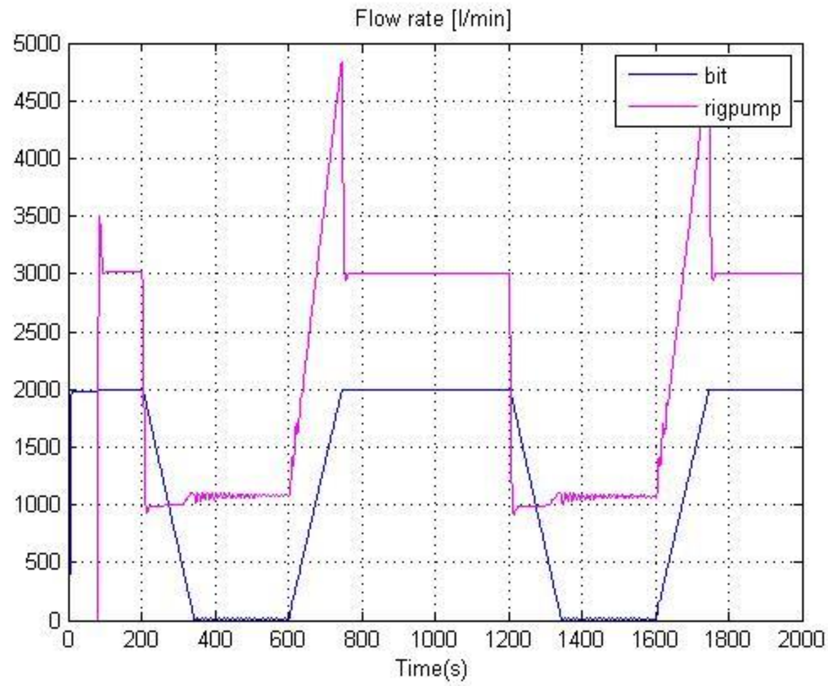

Figure 8.14 Flow rate with booster pump

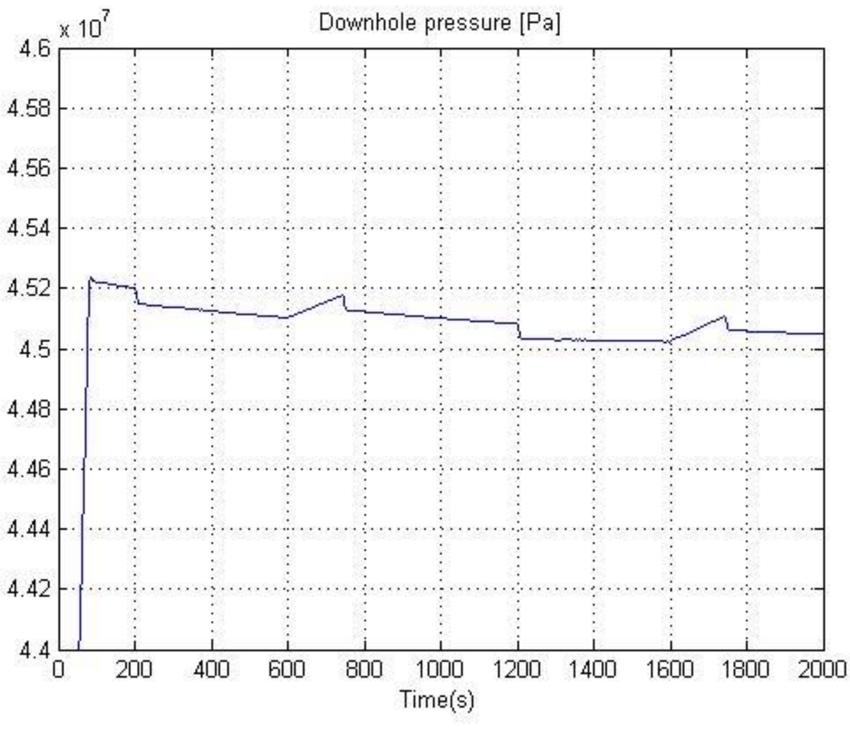

Figure 8.15 BHP with booster pump

A marginally improved BHP pressure profile compared without a booster pump. Insufficient booster pump analysis for the suggested parameters.

Conclusion

As the need for oil and gas increase in demand, more offshore wells are being drilled in deep-water environments. This increases the need for new drilling technology, and the Dual Gradient Drilling (DGD) technology being one of these. The literature study of this thesis show that DGD is the right way to approach the challenges met when drilling in deep-water environments.

The DGD system offers a broad aspect of advantages over conventional drilling.

- Reducing Non Production Time greatly
- Widen the drilling window
- Improved personnel safety
- Reducing environmental pollution by eliminating the “pump & dump” practice.

Because DGD is a new unconventional way of drilling, and mostly proven in theory, a wide array of challenges follow. In convention with this thesis the biggest challenge would be to overcome problems associated with the U-tube effect. However, being a conservative industry, perhaps the biggest challenge is to get DGD accepted in the field.

This thesis presents a method for modelling DGD operations by using Kaasa’s model for the DGD system. First finding an optimal lighter drilling fluid, then find optimal shutdown rate of mud pumps, and simulating the effects on the DGD with special emphasis to the bottom hole pressure, riser fluid level and the U-tube effect with PID controller.

The simulations show that optimal parameters can decrease the connection time during operations and thus decrease the Non Production Time. The simulations with back pressure pumps asserted to the system provides a better BHP, and that the booster pump have less effect on providing any benefits up to 1000 l/min.

The optimal value for lighter fluid density was found to be 620.8686 kg/m^3 and the optimal shutdown speed to be 0.0139, 155s. Further work from this thesis could involve simulations on cost reduction of the DGD system compared to conventional drilling system, and provide optimal input parameters for the different DGD methods in Kaasa’s model.

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Appendix

Kaasa's Model for solving DGD with PID controller.

```
%% Example of solving the Kaasa model using Euler integration
%
% Differential equations of Kaasa model:
% p_pdot = (beta_d/V_d)*(q_p-q_c)
% q_bdot = 1/M((p_p-p_c)-(Fd+Fb+Fa)*q_b*q_b+(rho_d-rho_a)*g*h)
% p_cdot = (beta_a/V_a)*(q_b+q_res+q_bpp-q_c)
% q_c = z_c*k_c*sqrt(p_c/rho_a)
%
% Parameters and initial values
clear all; % deletes all variables
close all; % removes all plot windows

% Constants
maxtime = 2000; % seconds
dt = 0.01; % euler step time
Ts = 1;% loop time step

%Operator parameters
q_p = 2000/60000; % 2000 l/min
q_bpp =0/60000; % 800 l/min
%q_bpp = 800/60000; % 800 l/min
q_c = q_p + q_bpp; % 2800 l/min
z_c = 0.7; % choke opening

q_top=1000/60000*0;
q_rb = q_c+q_top;
% Wellbore parameters
h = 2000;
beta_d =2e9;
beta_a =1e9;
V_d =17; % m3
V_a = 48; %m3
A_a = 30/h;
A_r = 0.01; % Riser area
M = 4.3e8;
Fd = 5e9;
Fb = 1e9;
Fa = 2e9;
rho_d = 1580;
rho_a = 1580;
g = 9.81;
k_c = 0.021;
rho_w= 620.8686;

% Define range

p_min=0*10^7; % p_p_m
p_max=5.0*10^7; % p_bhp_m
z_min=0;
z_max=0.20;

qrb_min=0;
```

```
qrb_max=20000/60000;

% reservoir parameters
p_pore = 3.05e7;
p_frac = 3.75e7;
ProdIndex = 0;%(100/60000)/5e5; % 100 l/min at delta p of 5 bar %
'permeability'

%Array initialization
p_p_ar = zeros(maxtime,1);
p_c_ar = zeros(maxtime,1);
p_b_ar = zeros(maxtime,1);
q_b_ar = zeros(maxtime,1);
q_c_ar = zeros(maxtime,1);
q_p_ar = zeros(maxtime,1);
q_bpp_ar = zeros(maxtime,1);
q_res_ar = zeros(maxtime,1);
r_ar = zeros(maxtime,1);
u_ar = zeros(maxtime,1);
y_ar = zeros(maxtime,1);
ufd_ar = zeros(maxtime,1);
h_rb_ar = zeros(maxtime,1);

% Initial values
p_p = 20e5;
p_c = 40e5;
q_b = 2000/60000;
p_b = p_p + rho_d*g*h;

h_rb = 100; % Level between water and drilling fluid measured from rb pump
h_rb_max= 1200; %Total riser height
p_rb =  rho_a*g*h_rb+ rho_w*g*(h_rb_max-h_rb);
q_of= 0; %Mud over flow at top of well
q_fill=0; %water rate at top of well (in/out)

%reference value
p_c_r = 15e5;
p_b_r = 450e5;

%Initialize controller
e = 0;
u = 0;
ufd = 0;
ufr = 0;
ufb = 0;
y = 0;
r = 0;
Kp = 100;
Ki = .1;


% Main iteration loop showing how the driller adjust the topside pump rate
q_0=1000/60000;
speed= 0.0139;
total=q_p/speed/q_0;
for time = 1:maxtime

    p_b_r_last = p_b_r;
```

```
    if (time > 200) && (time <= 200+total)
        q_p = q_p -1000/60000*speed; % (ramp down by 1000 l/min in one
minute)
    end

    if (time > 200+total) && (time <= 600)

        q_p = q_p;
    end

    if (time > 600)&& (time <= 600+total)
        q_p = q_p +1000/60000*speed; % (ramp up by 1000 l/min in one
minute)
    end

    if (time > 600+total) && (time <= 1200)

        q_p = 2000/60000;

    end
    if (time > 1200) && (time <= 1200+total)
        q_p = q_p -1000/60000*speed; % (ramp down by 1000 l/min in one
minute)
    end

    if (time > 1200+total) && (time <= 1600)

        q_p = q_p;
    end

    if (time > 1600)&& (time <= 1600+total)
        q_p = q_p +1000/60000*speed; % (ramp up by 1000 l/min in one
minute)
    end

    if (time > 1600+total)

        q_p = 2000/60000;

    end

    %Loop that can be used for lost circulation or influx
    %Pore pressure
    q_res = ProdIndex*(p_pore - p_b);

    if q_res < 0
        q_res = 0;
    end

    % Frac pressure
    q_loss = ProdIndex*(p_frac -p_b);
    if q_loss > 0
        q_loss = 0;
    end


    %store parameters
    p_p_ar(time) = p_p;
```

```
    p_c_ar(time) = p_c;
    p_c_r_ar(time) = p_c_r;
    p_b_ar(time) = p_b;
    q_b_ar(time) = q_b;
    q_p_ar(time) = q_p;
    q_c_ar(time) = q_c;
    q_bpp_ar(time) = q_bpp;
    q_res_ar(time) = q_res;
    q_rb_ar(time) = q_rb;
    u_ar(time) = u;
    y_ar(time) = y;
    r_ar(time) = r;
    ufd_ar(time) = ufd;
    ufr_ar(time) = ufr;
    h_rb_ar(time) = h_rb;
    q_of_ar(time) = q_of;
    q_fill_ar(time) = q_fill;



    %% Controller code

    % Feed forward from disturbance
    zfr = (V_a/beta_a)*(p_b_r_last-p_b_r);

    zfd = (q_p + q_bpp);



    % scale to percentace
    r = ((p_b_r-p_min)/p_max)*100.0; % reference is p_b1
    y = ((p_b-p_min)/p_max)*100.0; % controlled variable



    u = ((q_rb-qrb_min)/qrb_max)*100.0; % manipulated variable
 %   ufd_last = ufd;
    ufd = ((zfd-z_min)/z_max)*100.0; % feed forward disturbance
    ufr = ((zfr-z_min)/z_max)*100.0; % feed forward disturbance
    %ufb = u ;b1

    % controller code
    last_e = e;
    e=y-r;
%    delta_u=Kp*(e-last_e)+((Kp*Ts)/Ti)*e; % using Kp and Ti
    delta_u=Kp*(e-last_e)+(Ki*Ts)*e; % using Kp and Ki


    ufb=ufb+delta_u; % feedback


    u = ufb; % +ufd+ufr;
%    u = ufb+ufd_last; % +ufd+ufr; with time delay
%    u = ufb+ufd; % +ufd+ufr;
%      u = ufb+ufd+ufr; % +ufd+ufr;

    % limit u
    if u<=0
```

```
        u=0;
    end

    if u>100
        u=100;
    end


    %scale to physical values (only z are needed
%      z_c_old = z_c;
%      z_c = z_min + z_max*(u/100.0);
    q_rb_old = q_rb;
    q_rb = qrb_min + (qrb_max-qrb_min)*(u/100.0);

    %




    % Euler integration loop
    for eulerstep = 1:(1/dt)
        p_pdot = (beta_d/V_d)*(q_p-q_b);
        q_bdot = 1/M*((p_p-(p_c+p_rb))-(Fd+Fb+Fa)*q_b*q_b+(rho_d-
rho_a)*g*h);
        p_cdot = (beta_a/V_a)*(q_b+q_res+q_bpp+q_loss-q_c);

%          if h_rb < h_rb_max
          h_rbdot = (1/A_r)*(q_c+q_top-q_rb);
          q_of=0;
          q_fill= q_c-q_rb;
%          else
%              h_rbdot = 0;
%              q_of = (q_c-q_rb);
%              q_fill=0;
%          end

        p_p = p_p + p_pdot*dt;
        q_b = q_b + q_bdot*dt;
        p_c = p_c + p_cdot*dt;
        h_rb = h_rb + h_rbdot*dt;
        if h_rb>h_rb_max
            h_rb=h_rb_max
        end

        if p_c<0
            p_c=0;
            q_c=0;
        else
             q_c = z_c*k_c*sqrt(p_c/rho_a);
        end
        if q_b<0
            q_b=0
        end

            p_rb = rho_a*g*h_rb+ rho_w*g*(h_rb_max-h_rb);
            p_b1  = p_p+rho_d*g*h-(Fd+Fb)*q_b*q_b; % pump pressure
            p_b =p_rb+p_c+rho_a*g*h+Fa*q_b*q_b; % using choke pressure
```

```
    end
end

figure;
plot(1:maxtime,p_b_ar,'b');
title('Downhole pressure [Pa]');
grid
axis([0,2000,4.4*10^7,4.6*10^7])

figure;
plot(1:maxtime,p_p_ar,'b');
title('Pump pressure [Pa]');
grid

% figure;
% plot(1:maxtime,p_c_ar,'b',1:maxtime,p_c_r_ar,'k');
% legend('Measured','Reference');
% title('Choke pressure [Pa]');
% grid

figure;
plot(1:maxtime,q_b_ar*60000,'b', 1:maxtime,q_rb_ar*60000,'m');
title('Flow rate [l/min]');
legend('bit','rigpump');
grid

% figure;
%
plot(1:maxtime,r_ar,'k',1:maxtime,y_ar,'g',1:maxtime,u_ar,'b',1:maxtime,ufd
_ar,'r',1:maxtime,ufr_ar,'c');
% legend('Reference (r)','Controlled Variable (y)','Manipulated variable
(u)',...
%     'Feedforward dist (ufb)','Feedforward ref (ufr)');
% axis([1 maxtime 0 100]);
% title('Controller values');
% grid

figure;
plot(1:maxtime,h_rb_ar,'b');
title('Riser level [m]');
grid
%
%figure;
%plot(1:maxtime,p_b_ar,'b',1:maxtime,rho_a*g*(h+h_rb_ar),'r',1:maxtime,p_b_
ar-(rho_a*g*(h+h_rb_ar)),'g');
%title('Downhole pressure [Pa]');
%legend('ECD','Hydrostatic Part','Frictional Part')
%
% figure;
% plot(1:maxtime,rho_a*g*(h_rb_ar),'r',1:maxtime,p_b_ar-
(rho_a*g*(h+h_rb_ar)),'g');
% title('Downhole pressure [Pa]');
% legend('Hydrostatic pressure@Riserbase','Fricational Pressure Drop')
%
% figure;
% plot(1:maxtime,q_p_ar*60000,'g');
% title('Flowrate in [l/min]');
% legend('rigpump');
%
```

```
% figure;
% plot(1:maxtime,q_of_ar*60000,'b');
% title('Lost overflow [l/min]');
% legend('Overflow of drilling fluid');
%
% figure;
% plot(1:maxtime,q_fill_ar*60000,'g');
% title('Water fill at top [l/min]');
% legend('Water fill at top');
```

Optimization of lighter density fluid (without applying it in Kaasa's Model)

```
clear all; % deletes all variables
close all; % removes all plot windows

% Constants
maxtime = 2000; % seconds
dt = 0.01; % euler step time
Ts = 1;% loop time step

%Operator parameters
q_p = 2000/60000; % 2000 l/min
q_bpp =0/60000; % 800 l/min
q_c = q_p + q_bpp; % 2800 l/min
q_top=1000/60000*0; % *0 means without booster pump, *1 means with booster
pump
q_rb = q_c+q_top; % flow rate of subsea pump

%density
rho_d = 1580; % density in the drillstring
rho_a = 1580; % density in the annulus
rho_w= 400;  % density in the top side of the riser (800)

%sensitivity analysis
A_r = 0.01; % Riser area
h_rb_max= 1200; %Total riser height

% Wellbore parameters
h = 2000;
beta_d =2e9;
beta_a =1e9;
V_d =17; % m3
V_a = 48; %m3
A_a = 30/h;
M = 4.3e8;
Fd = 5e9;
Fb = 1e9;
Fa = 2e9;
g = 9.81;

% Define range
p_min=0*10^7; % p_p_m
p_max=5.0*10^7; % p_bhp_m
qrb_min=0;
qrb_max=20000/60000;

% reservoir parameters
p_pore = 3.05e7;
```

```
p_frac = 3.75e7;
ProdIndex = 0;%(100/60000)/5e5; % 100 l/min at delta p of 5 bar %
'permeability'

%Array initialization
p_p_ar = zeros(maxtime,1);
p_c_ar = zeros(maxtime,1);
p_b_ar = zeros(maxtime,1);
q_b_ar = zeros(maxtime,1);
q_c_ar = zeros(maxtime,1);
q_p_ar = zeros(maxtime,1);
q_bpp_ar = zeros(maxtime,1);
q_res_ar = zeros(maxtime,1);
r_ar = zeros(maxtime,1);
u_ar = zeros(maxtime,1);
y_ar = zeros(maxtime,1);
ufd_ar = zeros(maxtime,1);
h_rb_ar = zeros(maxtime,1);

% Initial values
p_p = 20e5;
p_c = 40e5;
q_b = 2000/60000;
p_b = p_p + rho_d*g*h;

h_rb = 100; % Level between water and drilling fluid measured from rb pump
p_rb =  rho_a*g*h_rb+ rho_w*g*(h_rb_max-h_rb);
q_of= 0; %Mud over flow at top of well
q_fill=0; %water rate at top of well (in/out)

%reference value
p_b_r = 450e5;

%Initialize controller
e = 0;
u = 0;
ufd = 0;
ufr = 0;
ufb = 0;
y = 0;
r = 0;
Kp = 100;
Ki = .1;

% given the setpoint of riser level
l_s=475;%h_rb_max/2;

rho_bar=rho_s(p_b_r,rho_a,g,h,Fa,q_p,h_rb_max,l_s);
```

With:

```
function rho_bar=rho_s(p_b_r,rho_a,g,h,Fa,q_p,h_rb_max,l_s)

rho_bar=(p_b_r-rho_a*g*h-Fa*q_p^2-rho_a*g*l_s)/(g*(h_rb_max-l_s));
x_opt=rho_bar;
```

```
rho_bar=fmincon('cost_d',x_opt,[],[],[],[],[],[],'constraint_d',[],p_b_r,rh
o_a,g,h,Fa,q_p,h_rb_max,l_s);
```

Suggested shutdown speed for main pump

```
clear all; % deletes all variables
close all; % removes all plot windows

% Constants
maxtime = 2000; % seconds
dt = 0.01; % euler step time
Ts = 1;% loop time step

%Operator parameters
q_p = 2000/60000; % 2000 l/min
q_bpp =0/60000; % 800 l/min
q_c = q_p + q_bpp; % 2800 l/min
q_top=1000/60000*0; % *0 means without booster pump, *1 means with booster
pump
q_rb = q_c+q_top; % flow rate of subsea pump

%density
rho_d = 1580; % density in the drillstring
rho_a = 1580; % density in the annulus
% rho_w= 500;  % density in the top side of the riser

%sensitivity analysis
A_r = 0.01; % Riser area
h_rb_max= 1200; %Total riser height

% Wellbore parameters
h = 2000;
beta_d =2e9;
beta_a =1e9;
V_d =17; % m3
V_a = 48; %m3
A_a = 30/h;
M = 4.3e8;
Fd = 5e9;
Fb = 1e9;
Fa = 2e9;
g = 9.81;

% Define range
p_min=0*10^7; % p_p_m
p_max=5.0*10^7; % p_bhp_m
qrb_min=0;
qrb_max=20000/60000;

% reservoir parameters
p_pore = 3.05e7;
p_frac = 3.75e7;
ProdIndex = 0;%(100/60000)/5e5; % 100 l/min at delta p of 5 bar %
'permeability'

%Array initialization
p_p_ar = zeros(maxtime,1);
```

```
p_c_ar = zeros(maxtime,1);
p_b_ar = zeros(maxtime,1);
q_b_ar = zeros(maxtime,1);
q_c_ar = zeros(maxtime,1);
q_p_ar = zeros(maxtime,1);
q_bpp_ar = zeros(maxtime,1);
q_res_ar = zeros(maxtime,1);
r_ar = zeros(maxtime,1);
u_ar = zeros(maxtime,1);
y_ar = zeros(maxtime,1);
ufd_ar = zeros(maxtime,1);
h_rb_ar = zeros(maxtime,1);

% Initial values
p_p = 20e5;
p_c = 40e5;
q_b = 2000/60000;
p_b = p_p + rho_d*g*h;

h_rb = 100; % Level between water and drilling fluid measured from rb pump
q_of= 0; %Mud over flow at top of well
q_fill=0; %water rate at top of well (in/out)

%reference value
p_b_r = 450e5;

%Initialize controller
e = 0;
u = 0;
ufd = 0;
ufr = 0;
ufb = 0;
y = 0;
r = 0;
Kp = 100;
Ki = .1;

% given the setpoint of riser level
l_s=h_rb_max/2;

%calculate the density of top liquid
rho_w=rho_s(p_b_r,rho_a,g,h,Fa,q_p,h_rb_max,l_s);

%shut down speed (q=q_p-speed*q_0*t)
speed_s=1/60*2;
q_0=1000/60000;

%calculate the optimal shut down speed
speed=find_speed(speed_s,q_p,Fa,g,rho_a,rho_w,h_rb_max,l_s,A_r,q_0);
```

With:

```
function speed=find_speed(speed_s,q_p,Fa,g,rho_a,rho_w,h_rb_max,l_s,Ar,q_0)

x_opt=speed_s;

speed=fmincon('cost_x',x_opt,[],[],[],[],[],[],'constraint_x',[],speed_s,q_
p,Fa,g,rho_a,rho_w,h_rb_max,l_s,Ar,q_0);
```